

Draft Final Report

Refinement of Selected Fuel-Cycle Emissions Analyses

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List of Terms and Abbreviations

AGA	American Gas Association
AP-42	EPA document on emission factors
atm	1 atmosphere = 14.7 psi
EMFAC	ARB model for determining vehicle g/mi emissions
API	American Petroleum Institute
ARB	California Air Resources Board
bbl	barrel of crude oil (42 gal)
Bcf	Billion standard cubic feet
bhp-hr	brake horsepower hour (dynamometer measurement)
Btu	British thermal unit
bsfc	brake specific fuel consumption
CA	California
CEC	California Energy Commission
CES	Category Emission Source
CHP	California Highway Patrol
CNG	compressed natural gas
CH ₄	methane
CO	carbon monoxide
CO ₂	Carbon dioxide
DOE	United States Department of Energy
DWT	dead weight ton
EMA	Engine Manufacturers Association
EMFAC	ARB vehicle emissions factor model
EVs	electric vehicles
FCC	fluid catalytic cracker
FFV	flexible fuel vehicle
GWh	GigaWatt hour
GRI	Gas Research Institute
GVW	gross vehicle weight
HHV	higher heating value of fuel or feedstock
hp-hr	shaft horsepower hour
IGT	Institute for Gas Technology
kg	kilogram
kWh	kilo-Watt hour
LACMTA	Los Angeles County Metropolitan Transportation Authority
LADWP	Los Angeles Department of Water and Power
LHV	lower heating value, HHV less heat of vaporization of water vapor in combustion products
LPG	liquified petroleum gas
H ₂	hydrogen
g	grams
gal	gallon
g/bhp-hr	grams per brake horsepower-hour
MWh	MegaWatt hour
mi	mile

MMBtu	Million Btu
MMscf	Million scf
MTBE	methyl tertiary butyl ether
mpg	miles per gallon
MW	molecular weight
NFPA	National Fire Protection Association
NGV	natural gas vehicle
NMOG	non-methane organic gases
NO _x	oxides of nitrogen
NPGA	National Propane Gas Association
NRDC	National Resources Defence Council
NREL	National Renewable Energy Laboratory
NSPS	new source performance standards
O ₃	ozone
OEM	original equipment manufacturer
POX	partial oxidation
psi	pressure, lb/in ² , 14.7 psi = 1 atm
QF	qualifying facility (power generator)
RECLAIM	Regional Clean Air Incentive Market
RFG	reformulated gasoline
ROW	rest of world
RVP	Reid vapor pressure
SoCAB	South Coast Air Basin
SCAQMD	South Coast Air Quality Management District
SCE	Southern California Edison
scf	standard cubic feet of gas, at 60°F and 1 atm
SCR	selective catalytic reduction
scfm	standard cubic feet per minute
SO _x	oxides of sulfur
SR	specific reactivity
SRWC	short rotation woody crops
t/d	tons/day
TAME	tertiary amyl methyl ether
TBA	tertiary butyl alcohol
TEOR	thermally enhanced oil recovery
THC	total hydrocarbons
ton	United States short ton, 2000 lb
TOG	total organic gases
TVP	true vapor pressure
UG	underground
U.S. EPA	United States Environmental Protection Agency
ullage	liquid fuel tank vapor space
V _e	equilibrium vapor
WLPGA	Western Liquid Propane Gas Association
WSPA	Western States Petroleum Association

1.0 Introduction

As emissions from passenger cars are reduced, emissions from vehicle refueling, fuel transportation, processing, and feedstock extraction represent a larger share of the total emissions that are attributed to vehicle operation. Quantifying these fuel-cycle emissions is an important aspect of assessing the total emissions impact of vehicle operation. This project builds upon the 1996 ARB study, “Evaluation of Fuel-Cycle Emissions on a Reactivity Basis” (Unnasch 1996), with the purpose of examining uncertainties and further document assumptions.

1.1 Background

Although significant strides have been made toward improving California’s air quality, health-based state and federal air quality standards continued to be exceeded in regions throughout California. Areas exceeding the federal 1-hour ozone standard include the South Coast Air Basin (SoCAB), San Diego County, San Joaquin Valley, the Southeast Desert, the Broader Sacramento area, and Ventura County. With promulgation of the new federal 8-hour ozone standard, more areas of the State are likely to be designated as nonattainment. Ozone (created by the photochemical reaction of reactive organic gases (ROG) and oxides of nitrogen (NO_x)) leads to harmful respiratory effects including lung damage, chest pain, coughing, and shortness of breath, especially affecting children and persons with compromised respiratory systems. Other environmental effects from ozone include crop damage. In addition, because ozone precursors, such as NO_x , also react in the atmosphere to form particulate matter (PM), reductions in NO_x will be crucial to meet existing state and federal PM_{10} standards, as well as the new federal standards for fine particulate matter ($\text{PM}_{2.5}$).

California’s plan for achieving the federal 1-hour ozone standard is contained in the California State Implementation Plan (SIP) that was approved by the ARB in 1994. A significant part of the SIP pertains to the control of mobile sources, which are estimated to account for approximately 60 percent of ozone precursors statewide. The SIP calls for new measures to cut ozone precursor emissions from mobile sources to half of what the emissions would be under existing regulations. These measures includes Improved Technologies for Light-Duty Vehicles, which calls for the adoption of technology-based emission control strategies for light-duty vehicles to be implemented beginning with the 2004 model year.

The pressing requirements for meeting air quality attainment goals have brought about amendments to ARB’s Low Emission Vehicle (LEV) standards with the LEV II standards (ARB 1998). The LEV II regulations will help achieve and maintain the federal 1-hour ozone standard in regions such as the San Joaquin Valley and the Sacramento area, the federal 8-hour ozone and particulate matter in a number of areas, and the state ozone and particulate matter standards throughout California.

The LEV II standards include a new emission standard category — Super Ultra Low Emission Vehicle (SULEV) for passenger cars and light trucks. A variety of vehicle technologies can reduce emissions to meet these levels. Vehicles powered by fuel cells,

hybrid electric drive trains, or advanced IC engines could qualify to meet ARB's SULEV standard.

ARB's revised ZEV program allows for additional flexibility to broaden the scope of vehicles that could qualify for meeting some portion of the ZEV requirement. Manufacturers would decide which mix of vehicles to use to meet the 10 percent ZEV requirement, with the exception that large volume manufacturers would have to meet at least 40 percent of the requirement using true ZEVs. The applicable ZEV allowance for each vehicle type would be determined based on a set of criteria designed to identify and reward ZEV-like characteristics in a variety of advanced-technology vehicles. In order for a vehicle to receive any ZEV allowance, a vehicle would need to satisfy the requirements for receiving the "baseline ZEV allowance." To receive this allowance, the vehicles would need to meet SULEV standards and also satisfy both second-generation on-board diagnostics requirements and zero fuel evaporative emission requirements. Vehicles that meet these requirements would be granted a 0.2 ZEV allowance. An additional allowance up to 0.6 is provided for vehicles realizing zero emissions potential with an extended range. This allowance could apply to hybrid electric vehicles with battery-only driving capability or fuel-cell-powered vehicles with nil emissions.

In addition, vehicles that use fuels with very low fuel-cycle emissions can receive a further ZEV allowance up to 0.2. The fuel-cycle emissions associated with a particular fuel are the total emissions associated with the production, marketing, and distribution, in grams per unit fuel. The marginal NMOG emissions associated with the fuel use by the vehicle must be lower than or equal to 0.010 grams per mile. For the purpose of providing this allowance, fuel-cycle NO_x emissions are not considered in the determination, since marginal NO_x emissions for virtually all fuels are expected to be uniformly low.

Fuel-cycle NMOG emissions can be over 0.1 g/mi for conventional gasoline vehicles. Fuels with low fuel-cycle emissions and high fuel economy have the potential for meeting ARB's ZEV requirements. This study includes refined estimates of emissions from fuel production and distribution processes and develops estimates for year 2010 fuel-cycle emissions to determine which fuels could qualify for a ZEV low fuel-cycle credit. The assumptions and uncertainties in fuel-cycle emissions were examined in order to identify uncertainties and expected ranges in emissions. Fuel economy for advanced vehicle technologies was also evaluated in order to determine gram per mile emissions. The results, which are presented in this report, can be used to evaluate whether qualifying vehicle technologies meet the low fuel-cycle emission allowance for meeting requirements of ARB's partial ZEV allowance.

1.2 Project Objectives

The primary objective of this study is to refine estimates of the mass emissions on a per-vehicle-mile basis, for selected vehicle fuels, for the fuel production and energy conversion portions of the total fuel-cycle, including fuel acquisition and refining, distribution, and refueling. The selected vehicle fuels are diesel fuel and liquefied petroleum gas (LPG) for internal combustion vehicles, and methanol for fuel-cell powered vehicles. Fuel-cycle emissions are compared to those from electricity generation for electric vehicles. The mass emissions of NO_x, NMOG, methane, CO, CO₂, and air toxics are quantified for each fuel and for each phase of the fuel cycle. Emission estimates were made for 1996 as a base year and for the year 2010 based on two different projection scenarios for each fuel, one pessimistic and one optimistic. The uncertainty associated with emissions from every step of each fuel cycle is estimated and those uncertainties are propagated to develop an overall uncertainty for each fuel.

This study provides a consistent basis for comparing the fuel-cycle emissions from a variety of fuels. LPG- and diesel-fueled IC engine vehicles, as well as methanol-powered fuel cell vehicles, have the potential for meeting SULEV requirements and also operating with low fuel-cycle emissions. Fuel-cycle emissions were determined for conventional vehicles in a 1996 study performed for ARB (Unnasch 1996). However, advanced vehicle technologies will have improved fuel economy, which will affect fuel-cycle emissions. Furthermore, uncertainties exist for some fuel-cycle emission sources, such as venting from LPG distribution trucks or breathing losses from bulk methanol storage tanks. These are potentially significant sources that require close analysis. Determining the emissions for each step in the fuel cycle requires a careful engineering analysis, and when possible, was based on actual fuel processing equipment experience. Obtaining speciated emissions to quantify the toxic components of hydrocarbon emissions also posed a challenge. The most significant source of hydrocarbon emissions is fuel spillage, refueling vapor losses, and storage tank venting. These emissions and others were analyzed in the context of a significant number of both SULEV and other vehicles operating in the year 2010.

The following sections discuss and review the methods used in this report to estimate and calculate the fuel-cycle emissions.

1.3 Project Approach

The fuel-cycle emissions associated with production and distribution of diesel, methanol, liquefied petroleum gas (LPG), and electricity were evaluated. Each fuel was evaluated based upon production from one or more feedstocks. Diesel, and LPG are considered for use in internal combustion engine vehicles. Electricity is assessed for pure ZEVs (battery-only electric vehicles), and methanol is considered for use in fuel cell vehicles with on-board methanol reformers.

The following outline summarizes the steps used in this project:

- Determine the physical characteristics and properties of all the fuels and feedstocks
- Evaluate the chemical compositions of the fuels, feedstocks, and their storage vapors as well as the products of combustion of fuel production equipment
- Outline scenarios for the production and distribution of fuels
- Determine the emissions of NO_x, CO, CO₂, CH₄, and NMOG for the processes involved with each scenario
- Develop per-gallon fuel-cycle emissions estimates
- Estimate vehicle fuel economy
- Compare fuel-cycle emissions on a per mile basis

In this study, fuel-cycle emissions are first determined per unit of fuel, which allows for better comparison with other studies and provides better insight into the origin of the emission estimates. Thereafter, the emissions are related to fuel economy to determine gram per mile emissions. This approach allows other values for fuel economy to be investigated more readily.

1.4 Report Scope

Table 1-1 summarizes the fuel/feedstock combinations that were considered in this study. As indicated in the table, several fuel/feedstock combinations are complicated by the fact that several products are made from the same feedstock and many fuels can be produced from several feedstocks. Different mixes of feedstocks are also used in fuel production. For example, a variety of crude oil sources make up the feedstock for California refineries, and this mixture will change in the future. Methanol is currently produced from natural gas, while production from biomass has been considered as an option for the future. Natural gas is produced from gas fields as well as a byproduct of oil production, and the gas can be used for many purposes, including the manufacture of synthetic liquid fuels or methanol. LPG is produced during oil refining and derived from natural gas liquids, a product of natural gas production. Electricity can be produced from a myriad of feedstocks, which range in CO₂ impact from solar energy to coal.

The alternative fuels listed in Table 1-1 are used to a limited extent in California. Many vehicles have been converted to operate on LPG and manufacturers are beginning to offer purpose built vehicles. Several thousand flexible fuel methanol vehicles (FFV's) have been built as production vehicles for operation in California. FFVs are capable of operating on either M85, gasoline, or any mixture of these fuels. Prototype fuel cell cars and buses and over 300 transit buses have also been operated on M100. Electric vehicles will make up a significant portion of California's vehicle fleet as part of ARB's Low-Emission Vehicle program. Expanded use of electric vehicles (EVs) has also been considered as a means of reducing emissions to meeting federal Clean Air Act emission

requirements. The feedstocks in Table 1-1 may not all be used in the short term. The significance of feedstock options and combinations of fuels and feedstocks that are addressed in this study are discussed in Section 3.

Table 1-1: Fuels, Feedstocks, and Refining Processes Evaluated in this Study

Feedstocks	Fuels
Crude Oil	Diesel, reformulated diesel, LPG
Natural gas	Methanol, synthetic diesel, LPG
Landfill gas	Methanol
Biomass	Methanol
Crude oil	Electricity
Natural gas	
Coal	
Biomass	
Hydroelectric	

For the purposes of this study, fuel-cycle emissions represent fuel extraction, production, distribution, and vehicle conversion as illustrated in the example for diesel processing in Figure 1-1. This definition is often referred to as “well to wheels”. The analysis considers the marginal, or incremental gallon (or equivalent fuel unit) consumed in the South Coast Air Basin (SoCAB). In order to help evaluate the impact on air quality, the emissions will be geographically categorized. Energy needed for fuel production in the South Coast Air Basin will also be sorted to count sources that correspond to incremental fuel production.

Fuel-cycle emissions were analyzed over a range of assumptions. The major factors that affect fuel-cycle emissions in this study include the following:

- Vehicle fuel economy (which is proportional to fuel-cycle emissions)
- Reduction in emissions due to stationary control measures in Southern California
- Different alternative fuel production feedstocks and technologies
- Control of vehicle refueling emissions

Emissions were estimated for conditions in 1996 and 2010 with emission regulations, and vehicle fuel economy consistent with these time periods. These estimates serve as upper and lower bounds. Table 1-2 shows the scenarios explored in this study.

A significant fraction of the new vehicle mix in the year 2010 is expected to be comprised of SULEVs and ultra-low-emission vehicles (ULEVs). This time period is appropriate for the evaluation of fuel-cycle emissions since a significant fraction of these vehicles may be alternative-fueled or powered by hybrid electric drivetrains.

Figure 1-1: Fuel-Cycle Emission Source

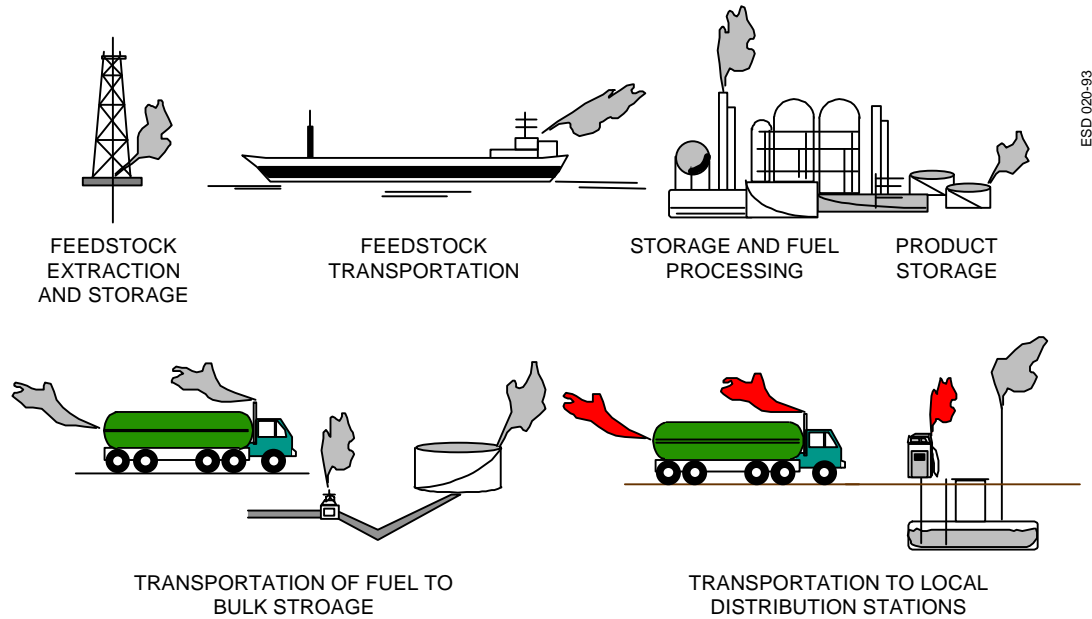


Table 1-2: Scenarios and Timing for Fuel Production and Distribution

Scenario	Year	Description
1	1996	Current emissions. Equipment meets prevailing standards. Refinery emissions based on 1997 SCAQMD inventory.
2	2010	Equipment meets standards applicable in year 2010. Refinery emissions adjusted from 1990 inventory for local rules. Emissions consistent with ARB factors for fuel distribution. Currently available fuel production and distribution processes.
3	2010	Same as Scenario 2. Lower assumptions on distribution emissions. New alternative fuel production facilities and technologies. Lower fuel spillage. Assumes more CO ₂ -free feedstocks.

Assumptions were made regarding which technologies represent current and future fuel production. Scenario 1 represents the current situation (1996) and Scenarios 2 and 3 represent a range of emission estimates for the year 2010. The assumptions for each scenario correspond to parameters discussed in Section 3. Advanced vehicle fueling systems that minimize refueling emissions were assumed for vehicles that meet SULEV requirements. The project focuses on fuels that are close to meeting the SULEV standards. Refueling emissions are also calculated.

This study follows the approach used by other studies (Unnasch 1989 and 1996, Wang 1999, DeLuchi 1991, and Balles 1992). Emissions are estimated for steps in the fuel production and distribution process. This study relies on both process-specific analyses, using emission factors for fuel-cycle steps, and emission inventories or aggregate data. The report is organized along the modular approach that was used to calculate emissions.

Other than combustion and fugitive emissions associated with fuel production and distribution and vehicle CO₂ emissions, no other environmental impacts, are considered in this report. In order to consider the total emissions from fuel production and distribution, exhaust and evaporative emissions need to be added to the fuel-cycle emissions in this study. Only emissions from fuel production equipment are considered in this study. Emissions associated with the production of equipment, facilities, or vehicles have not been included in this report. Spills and upsets are only considered when they are part of routine operations. For example, the probability-weighted emissions from fuel tanker shipment spills are not considered, but average emissions from vehicle fueling spills are counted.

1.5 Report Organization

Section 2 outlines the basic assumptions regarding fuel compositions and fuel properties used in the study. It also discusses NMOG speciation data for fuel, fuel vapor, and exhaust emission. Section 3 presents an overview of the fuel production scenarios for each fuel. The geographical area where fuels are produced and distributed are identified so transportation and distribution emissions can be accounted for. Emission rates for equipment that are used in the production and distribution of fuels are presented in Section 4. A data base approach was used to relate the mix of equipment, storage, and transportation modes in Section 3 with emission rates in Section 4. Section 5 discusses the trends in vehicle fuel economy and the likely fuel economy for diesel, LPG, and methanol fuel cell vehicles. The fuel-cycle calculation procedure is discussed in Section 6. The results per unit of fuel produced are presented in Section 7. A final series of calculations relates vehicle fuel economy with emissions per unit of fuel to show the fuel-cycle emissions on a gram per mile basis.

2.0 Fuel and Feedstock Properties and Compositions

The fuels and feedstocks properties and compositions affect their fuel-cycle emissions. This report accounts for the effect of fuel composition on processing requirements and efficiency, evaporative and fugitive emissions, and combustion emissions. These fuel and feedstock properties and compositions are summarized in this section. The relevant properties include vapor pressure, liquid density, vapor molecular weight, carbon content, and heating value. Each fuel and feedstock is discussed in the following sections. Table 2-1 summarizes the energy and carbon content of the various fuels discussed throughout this report. A range of properties corresponds to most of the fuels and feedstocks in Table 2-1. The values in the table are representative of average compositions. Methanol, ethanol, MTBE, hydrogen, CH₄, and CO are pure compounds with invariant compositions. Feedstocks such as coal, crude oil, and biomass have a wide range in carbon content and heating value. Not all of these fuels are evaluated in this report; however, they are components of the fuel cycle. For coal and crude oil, the range in the ratio of carbon content to energy content is relatively small (Schmidt).

Table 2-1: Energy and Carbon Content of Fuels

Fuel	Carbon Content		Energy Content				Density (lb/gal)
	C (wt %)	C (lb/gal)	HHV (Btu/lb)	HHV (Btu/gal)	LHV ^b (Btu/lb)	LHV (Btu/gal)	
Diesel, alternate formulation	86.7	6.24	20,010	139,680	18,300	130,800	7.13
Low aromatics diesel	85.9	—	19,560	137,990	18,750	129,350	6.89
Reformulated diesel ^g	86.3	6.06	18,600	137,500	18,360	128,900	7.02
FTD diesel	86.0	5.53	19,900	128,500	18,480	118,800	6.43
Methanol	37.5	2.48	9,800	64,800	8,600	57,000	6.6
Residual oil	90.0	7.29	18,300	148,200	17,700	143,800	8.1
Crude oil	84.5	6.51	19,100	147,800	17,730	136,500	7.7
Coal	66.6	—	12,100	—	—	—	—
Natural Gas ^c	73.6	3.38 ^d	22,500	103,000 ^d	20,300	92,800 ^d	4.59 ^d
LPG from petroleum	82.0	3.44	21,570	90,600	19,770	83,200	4.20
LPG from natural gas	81.8	3.42	21,570	90,160	19,770	82,600	4.18
Hydrogen	0.0	0	61,100	32,400 ^d	51,600	27,400 ^d	0.53 ^d
MTBE ^f	68.1	4.22	16,300	100,900	15,100	93,500	6.2
Conventional gasoline	84.6	5.08	20,800	124,600	19,200	115,400	6.0
Phase 2 RFG	82.8	4.97	20,300	122,000	18,800	113,000	6.0
CH ₄	75.0	3.15 ^d	23,900	101,200 ^e	21,500	91,100 ^d	4.2 ^e
CO	42.9	3.22 ^d	4,300	32,400 ^e	4,346	32,400 ^d	7.5 ^e
Landfill gas	35.6	2.62 ^d	6,570	48,300	5,900	43,500	7.4
Biomass, dry	52	—	8,700	—	8,200	—	—
Carbon	100	15.3	14,087	215,000	14,087	215,000	15.3

^aHHV = Higher heating value.

^bLHV = Lower heating value.

^cNatural gas distributed in California.

^dPer 100 scf.

^eMTBE = Methyl tertiary butyl ether (CH₃OC₄H₉).

^fMathPro 1999, Case 8 HHV and density reported other values estimated.

Source: Acurex 1996, ANL 1999, MathPro 1999.

Carbon content as weight percent or per MMBtu is used to determine CO₂ emissions from fuel combustion. Higher heating values are used to relate fuel use to energy consumption for process efficiency calculations while lower heating values are used to compare vehicle fuel consumption. The molecular weight of fuels corresponds to vapor density and associated evaporative emissions. The values in Table 2-1 were used throughout the report.

2.1 Fuel Composition and Properties

Fuel composition and properties affect many aspects of the fuel-cycle analysis. Liquid fuel and vapor composition and properties are necessary to predict emissions from fuel transfer operations. The vapor pressure of fuels affects the mass emissions from vapor transfers. The composition of fuels affects the mix of toxic compounds from liquid spills as well as that of vapor emissions. Fuel specifications affect refinery energy requirements and to some extent emissions. Finally, the composition of fuels needs to be consistent with values used for energy content, vapor pressure, and vehicle fuel economy.

The following sections summarize the physical properties of the fuels considered in this study. Since the fuels in this study can be represented by a variety of formulations, presenting the potential range in fuel properties provides some insight into how the results of this study might be affected by different fuel properties.

2.1.1 Diesel

Diesel fuel is used to fuel compression-ignited light-and heavy-duty engines. The popularity of diesel as a fuel for passenger cars has dropped in recent years while diesel is the dominant fuel for trucks. Unlike gasoline, diesel has a low vapor pressure and a low octane number. High quality diesel is characterized by a high cetane number. The ARB implemented a specification for clean diesel that took place in October 1993. This fuel required lower sulfur and aromatics (0.05 and 10 percent maximum, respectively) with an option to meet an alternative specification that results in equal emission benefits. Much of the diesel fuel sold in California after 1993 met alternative specifications that achieved the same emission reductions as the 10 percent aromatics formulation. Table 2-2 shows how the heating value, density, sulfur content, and cetane index for various formulations. The low aromatics and alternative formulations were sold in California in 1994.

Several diesel formulations were evaluated for the engine manufacturers association (EMA) by MathPro. This analysis included a range of sulfur levels for on-road, off-road, and light-duty diesel fuel. The very low sulfur diesel formulation (20 ppm sulfur) was selected to represent reformulated diesel in California. The properties of other diesel formulations included in the EM study are also shown.

Table 2-2: Diesel Fuel Properties

Fuel	RVP ^a (psi)	Aromatics (wt %)	Sulfur (ppm wt)	Cetane Index	API Gravity
Low aromatics diesel ^b	0.03	8.3	60	50	39.7
Diesel, alternate formulation ^b	0.03	27.8	250	55.3	33.8
Very low sulfur diesel (RFD) ^c	0.03	30.5	20	47.8	36.5
150 ppm diesel ^d	0.03	30.5	150	47.4	36.2
FT diesel	0.03	0.0	0.0	75	45

^aRVP = Reid vapor pressure (EPA AP-42).

^bSamples from fuel sold in California in 1994, Unnasch 1994.

^cProperties from MathPro Case 8.

^dProperties from MathPro Case 9a.

The properties of diesel fuel for this study are shown in Table 2-2. RVP values for diesel are not frequently measured. EPA's document on emission factors from stationary sources (EPA AP-42) shows true vapor pressures for diesel fuel as a function of fuel temperature. The heating value and density of the very low sulfur and low aromatics formulation are consistent with higher hydrogen content in the fuel (shown in Table 2-1).

2.1.2 LPG

The composition of LPG represents typical analyses of fuel collected in Southern California (Unnasch 1994). Propane and butanes produced in oil refineries are now mostly converted to alkylate, used in the production of ethers, or sold into the chemical market; however, this LPG could be diverted to a higher value fuel market. Petroleum-based LPG contains several percent propylene while natural gas based LPG contains no propylene or other olefins. LPG compositions from petroleum and natural gas are shown in Table 2-3.

The propylene (C₃H₆) content of the LPG samples in Table 2-3 indicates that one sample was largely from petroleum-derived sources and another sample was derived from natural gas. The majority of this sample came from an oil refinery. ARB's specification limits propylene to a maximum of 5 percent; however, observations of propylene in commercial LPG have shown lower levels. LPG is stored in pressure vessels. At 100°F the vapor pressure is about 190 psi.

2.1.3 Synthetic Diesel

FT diesel is a superior fuel for compression ignition engines. It contains virtually no sulfur or aromatics. Its cetane number is 75 compared to 50 for high quality diesel fuels. Both sulfur and aromatics are related to particulate production in diesel engines, while a high cetane number generally results in lower NO_x emissions.

Table 2-3: Composition and Properties of Gaseous Fuels

Property	Pipeline Natural Gas		LPG from Petroleum		LPG from Natural Gas	
Carbon (wt %)	73.6		82.0		81.8	
LHV ^b (Btu/lb)	20,300		19,770		19,770	
(Btu/gal)	92,800 ^c		83,200		82,600	
Density (lb/gal)	4.6 ^c		4.21		4.18	
Composition	(vol %)	(wt %)	(vol %)	(wt %)	(vol %)	(wt %)
N ₂	1.6	2.6	0	0	0	0
CO ₂	1.0	2.5	0	0.0	0	0
CH ₄	93.2	86.4	0.05	0.03	0.1	0.06
C ₂ H ₆	3.1	5.4	0.5	0.37	2.0	1.48
C ₃ H ₈	0.7	1.8	94.15	93.9	97.0	97.5
C ₃ H ₆	0	0	2.3	2.3	0	0
C ₄ H ₁₀	0.4	1.3	3.0	3.4	0.9	1.0
C ₅ H ₁₂	0	0	0	0	0	0

^aLPG = Liquefied petroleum gas.^bLHV = Lower heating value.^cper 100 scf

Source: Unnasch 1994.

The volumetric heating value of FT diesel is slightly lower than that of conventional diesel fuel since it has higher hydrogen to carbon ratio. Similarly, it has a higher energy content than conventional diesel fuels on a Btu/lb basis. The fuel is colorless and odorless and miscible with conventional diesel fuels.

South Africa and Russia have been operating coal based FT plants since the 1950's. Typical units produce 5,000 to 13,000 bbl/day of synthetic fuel and provide a substantial portion of South Africa's fuel.

More recently, major oil companies have been constructing FT plants that operate on remote natural gas. Shell Malaysia completed at 10,000 bbl/day plant that produces middle distillates and paraffins in 1994. In 1997, ARCO announced plans to build a small-scale gas to liquids plant on the West Coast of the United States. Texaco also announced plans to build a mobile plant that will produce synthetic diesel on a commercial basis. Exxon is expected to site a 100,000 bbl/day plant in Qatar. FT plant capacity could be over 2 millions bbl/day by 2005. Plants operating on both remote natural gas as well as North American gas are possible. An FT diesel plant in Alaska could produce fuels that could be sent to market down the 800-mile trans-Alaska pipeline. The production of such fuels could make up for declining oil production. In 1997, Tosco and Paramount Petroleum also blended Shell's FT diesel to produce clean diesel for sale in California.

2.1.4 M100

The composition of M100 is 100 percent methanol. The composition of fuel vapors is the same as that of the liquid. M100 contains trace contaminants of water and hydrocarbons (Table 2-4). However, fuel cell vehicles with methanol stream reformers

will likely not be able to operate effectively with percent levels of hydrocarbons. Therefore, hydrocarbon free fuel was assumed. Hydrocarbon levels in the ppm range would not affect steam refiners and these levels would have an insignificant impact on fuel-cycle emissions. Measurements of M100 contaminants from vehicle demonstration programs indicate negligible hydrocarbons and typically less than 1000-ppm water. The effect of this level of water on vapor pressure and heating value is negligible.

Table 2-4: Properties of Methanol Fuels^a

Component	RVP ^b (psi)	Composition
Methanol	4.63	>99.85%
Hydrocarbons ^c	—	<1,000 ppm
Water ^c	—	<5,000 ppm

^aM100 = 100 percent (neat) methanol.

^bRVP = Reid vapor pressure.

^cHydrocarbon and water level assumed for the purpose of determining fuel-cycle emissions. Lower levels may be required for fuel cell vehicle operation.

2.2 Feedstocks

2.2.1 Crude Oil

Crude oil contains a mixture of hydrocarbons with a range of compositions. Since crude oil contains light hydrocarbon components it has a higher vapor pressure than diesel. Crude oil is characterized by its API gravity that is inversely proportional to specific gravity. This property determines how “heavy” the oil is and relates to its carbon content and heating value. The properties of typical crude oil are shown in Table 2-1.

2.2.2 Natural Gas

Table 2-3 shows the properties of gaseous fuels. The natural gas compositions are an average of measurements provided by SoCalGas for gas delivered in Southern California. These values resemble closely the weighted average of natural gas composition for ten U.S. cities reported by GRI¹ (Liss 1991). While some natural gas supplies can vary significantly in composition, 80 percent (10th through 90th percentiles) of natural gas reported by GRI had a methane content within 88.5 to 96.4 percent. All gas that is currently sold in California is reported to have a relatively high methane content with typical methane contents above 92 percent, which is within ARB's vehicle fuel specification of 88 percent (vol).

¹ Mean composition (vol%) for ten cities in the U.S. was methane: 93.2, ethane: 3.6, propane: 0.8, >C₄: 0.5, inerts 2.8.

As natural gas demand increases to meet vehicle requirements, California will need to import more natural gas. This gas will probably be supplied from Canadian and Southwest U.S. sources (Thomason 1993)². Canadian gas has higher methane content because hydrocarbons are extracted for LPG use. An average of 50 percent Canadian gas and 50 percent Southwest gas results in a mixture that is very close to the value in Table 2-3. Since the exact mix of incremental gas for vehicle fuel is difficult to predict and the composition in Table 2-3 is also representative of U.S. gas as well as possible new gas supplies to California, this composition is used throughout the study. The compositions in Table 2-3 are also shown as weight percent values so they can be treated consistently with liquid fuel compositions and to allow for calculation of ozone potential on a mass basis.

2.2.3 Landfill Gas and Digester Gas

Landfill gas is produced when organic material decomposes in a landfill. The organic material converted to methane and CO₂ through biological decomposition. Traces of sulfur containing compounds and chlorinated compounds occur in landfill gas. Air can also be entrained in landfill gas. When landfill gas is removed from the center of a landfill the gas has a higher methane and CO₂ content. Gas that is extracted from the periphery of a landfill contains more nitrogen and some oxygen. Table 2-5 shows the compositions of landfill gas and digester gas which are potential feedstocks for methanol production. Data from a digester included speciations of hydrocarbons that determined that non-methane hydrocarbons were below 0.1 percent by volume.

Table 2-3: Composition and Properties of Gaseous Fuels

Property	Digester Gas		Landfill Gas	
Carbon (wt %)	44.5		35.9	
LHV ^a (Btu/lb)	7,910		6,350	
(Btu/gal)	5,550		45,300	
Density (lb/gal)	7.02		7.1	
Composition	(vol %)	(wt %)	(vol %)	(wt %)
N ₂	1.1	1.2	16	16.5
CO ₂	37.6	62.1	31	50.4
CH ₄	61.3	36.8	50	29.5
C ₂ H ₆	0	0	0	0
C ₃ H ₈	0	0	0	0
C ₃ H ₆	0	0	0	0
C ₄ H ₁₀	0	0	0	0
C ₅ H ₁₂	0	0	0	0
O ₂	0	0	3	3.5

^aLHV = Lower heating value.

Source: Unnasch 1994.

² Canadian gas composition (vol%) methane: 96.99, NMHC: 1.46. Southwestern gas composition (vol%) methane: 91.48, NMHC 6.33).

2.2.4 Biomass

Lumbermill waste and forest thinnings were considered for plants operating on forest material. Removing biomass from forests that have a high risk of fire is a source of feedstock for electric power generation and planned ethanol production. The benefits of harvesting forest thinnings also include increasing water available for larger trees, reduced fire fighting costs, and potentially reducing insect damage.

Providing a steady amount of forest material year round is not always possible as environmental constraints limit timber harvesting to non-rainy months. The amount of forest material that could be available in proximity to a potential methanol plant limits the plant size to about 40 million gallons per year. This plant size is relatively small for a capital-intensive methanol facility. A mixture of urban waste and agricultural waste was assumed necessary to provide a plant size over 100 million gallons per year. Urban wood waste and tree trimmings could provide additional biomass feedstocks for methanol production. Sewage sludge has also been considered a feedstock for gasification.

Wood waste, tree trimmings, and yard waste are separated in many areas. Competing uses for the highest quality of urban wood waste would require blending with lower value feedstocks, such as tree prunings, to reduce feedstock costs. Most urban wood waste that is currently burned in biomass power plants consists of larger branches from tree pruning and removal with very little clean wood residue from furniture and lumber operations. Urban wood waste is a limited resource for existing biomass power plants and if used as a methanol feedstock the price and transportation distance would increase. Chipped tree branches and yard waste are other potential feedstocks. These materials are either composted or used for landfill cover and are not suitable as fuels for biomass power plants. Sorting and quality control steps may need to be taken with branches and yard waste as these can quickly rot, may contain unexpected contaminants, and can have a high ash content.

Energy crops could provide additional feedstocks for methanol production. Eucalyptus was assumed as a potential energy crop since it has low water requirements and could be grown in many parts of California. It also could be used in areas where ground water contamination may be mitigated by planting trees. Table 2-6 shows the composition of some biomass materials.

2.3 Electric and Steam Energy

Electrical energy in this study is reported in electric kWh. Thermal energy used in generating electricity and other fuels is reported in Btu. With this approach, electrical energy and thermal energy should not be confused. Converting electrical energy to thermal energy incorporates the efficiency of the power conversion process. For example, if a diesel engine generator set operates with an efficiency of 34.1 percent (HHV), 10,000 Btu are required to produce 1 kWh.

Table 2-6: Composition of Biomass Materials

Component	Plne		Eucalyptus		Poplar	
	Wet	Dry	Wet	Dry	Wet	Dry
Moisture	57.06		40.4		5.6	
Carbon	23.16	53.93	30.59	51.32	47.05	49.84
Hydrogen	2.68	6.23	3.67	6.16	5.73	6.07
Nitrogen	0.85	1.97	0.7	1.18	0.41	0.43
Sulfur	0.13	0.31	0.08	0.13	0.05	0.05
Ash	1.46	3.41	3.96	6.64	0.47	0.5
Oxygen	14.66	34.15	20.6	34.57	40.69	43.11
Total	100	100	100	100	100	100
HHV (Btu/lb)	3,996	9,306	5,265	8,834	7,421	7,861

Source: A. D. Little

Both electric power and steam can be inputs and outputs for fuel production processes. When power or steam are exported from a fuel production facility, energy is displaced from another facility. Exports of power and steam result in a reduction in energy use and emissions and are counted as a credit in this study. The quantification of credits is shown in Table 2-7.

Table 2-7: Energy Credits for Power and Steam

Primary Energy	Location	Energy Displaced (HHV)	Carbon Displaced
1 kWh electricity	Indonesia ^a	10,000 Btu ^b	0.31 lb
10,000 Btu steam	Indonesia	12,500 Btu ^b	0.39 lb
1 kWh electricity	California	8,500 Btu ^c	0.32 lb

^a Surrogate for remote location.^b Natural gas.^c Estimated marginal energy from California mix.

3.0 Definition of Fuel Cycles

This study considers fuel-cycle emissions from vehicle fuels. The analysis considers the marginal, or incremental gallon (or equivalent fuel unit), consumed in the SoCAB.

Three example scenarios were developed to cover the range in emissions due to fuel-cycle assumptions. Many of these fuels can be produced from several feedstocks. Table 3-1 shows the fuel/feedstock combinations considered in this study. The codes that correspond to the fuels and feedstocks are used later to identify emission rates in a database. The combination of feedstocks and fuels represents a specific combination of production technologies and feedstocks. For example, methanol from natural gas is considered separately from methanol from biomass, while a combination of feedstocks is considered for electricity production.

Table 3-1: Feedstock/Fuel Combinations Considered in This Study

Feedstock	Code ^a	Fuel	Code	Vehicle ^b
Crude Oil	o	Diesel	D	CI IC
Crude Oil	o	RFD	RD	CI IC
Crude Oil	o	LPG	P	SI IC
Natural Gas	n	Synthetic Diesel	F	CI IC
Natural Gas	n	LPG	P	SI IC
Natural Gas	n	Methanol	M	Steam reformer PEMFC
Landfill Gas	l	Methanol	M	Steam reformer PEMFC
Biomass	b	Methanol	M	Steam reformer PEMFC
Various	x	Electricity	J	Battery only EV

^aCodes refer to feedstock and fuel designations used in database.

^bCI IC = compression ignition internal combustion engine, SI IC = spark ignited internal combustion engine, PEMFC = proton exchange membrane fuel cell, EV = electric vehicle.

The fuel-cycle emissions in this study are represented as the weighted average of different production and distribution technologies described in this section. Some fuel/feedstock combinations, such as methanol from natural gas, were represented separately while others were combined to simplify the comparison of fuels in Section 7. The basis for scenarios, mix of feedstocks, as well as production and distribution technologies is described below.

3.1 Scenarios

The scenarios in this study, identified as Scenarios 1 through 3, represent emissions for the years 1996 and 2010. Scenario 1 considers emissions for the base year, 1996. The two scenarios for the year 2010 consider a high and low estimate based on certain technology mix feedstocks, emission control assumptions, and transportation distances.

3.2 Information Organization

Identifying emissions by spatial location complicates the analysis of fuel-cycle emissions considerably, since fuel and feedstock transportation distributes emissions in several of the geographic locations considered in the study. Therefore, the information for this project is organized into a database that calculates spatial emissions and combines these results with vehicle fuel economy to represent fuel-cycle emissions on a g/mi basis. The information is in three databases that include the following information:

- Production and distribution emission rates
- Emission weighting and spatial distribution
- Vehicle fuel economy

Assumptions for emission scenarios, geographic distribution, production and distribution for the fuel/feedstock combinations, and production and distribution technology mixes are discussed below. Further information on the specific mix of technologies and energy use parameters is provided in Section 4. These databases are included in Volume 2. Since marginal emissions in the SoCAB represent a limited set of emissions sources, all of these sources are presented in Section 6.

3.2.1 Fuel Production Phases

These steps are categorized into eight production and distribution phases shown in Table 3-2. These phases are grouped into the categories extraction, production, marketing, and distribution, which are later used for presenting the combined emissions in Section 6.

Table 3-2: Fuel-Cycle Emissions Were Categorized into Eight Production and Distribution Phases

Phase No.	Description
<u>Extraction</u>	
1.	Feedstock extraction
2.	Feedstock transportation
<u>Production</u>	
3.	Fuel processing/refining
<u>Marketing</u>	
4.	Fuel storage at processing site
5.	Transport to bulk storage
6.	Bulk storage
7.	Transport to local distribution station
<u>Distribution</u>	
8.	Local station distribution

3.2.2 Geographic Distribution

Because some fuels will be produced outside of California, emissions from the entire fuel-cycle will not directly impact California urban areas. For this reason, it is

important to identify the percentage of feedstock extracted or fuel produced in each area. In order to help evaluate the impact on local emission inventories and air quality as well as considering the differences between local emission rules, the emissions were geographically categorized. Emissions from fuel production can then be allocated according to the locations in Table 3-3. This table also shows the acronyms used to identify each of these areas for this report.

Table 3-3: Location of Emissions and Acronyms

Location	Acronym
Within the SoCAB	SC
Within California, but outside the SoCAB	CA
Within the U.S., but outside of California	U.S.
Rest of the World, outside the U.S.	ROW

Emissions for fuel or feedstock transportation and distribution are also divided into the four geographic distribution categories. For example, emissions for ships entering and exiting the San Pedro ports were attributed to the SoCAB for a portion of the trip. The balance of these emissions was attributed to the rest of the world. Both land and sea transport emissions were allocated proportionally according to their transport route.

This study is intended to be used to evaluate marginal emissions from fuel production. Information is also provided to determine average emissions. The interpretation of which emissions correspond to marginal fuel production depends on several factors that are discussed in Section 3.3. The focus on marginal emissions raises questions of transporting emissions into and out of the state. For example, methanol could be sold for vehicle use in the SoCAB without any production emissions affecting local air quality. Similarly, gasoline is transported to other states from the SoCAB while the refinery emissions contribute to emission inventories in the SoCAB.

3.3 Marginal Emissions

This study pays considerable attention to the marginal fuel-cycle emissions. Many industry stakeholders participated in the 1996 Acurex study. During the course of projects meetings, it was clear that the subject of marginal emissions was important to the stakeholders. When the subject of fuel-cycle emissions becomes meaningful in a regulatory or economic sense, stakeholders become acutely interested in the outcome of such an analysis. Since marginal emissions are generally lower than average emissions and marginal emissions reflect the impact on air quality, these emissions are generally of greatest interest.

Marginal emissions are affected by local air quality regulations, permit requirements for new facilities, permits for existing power generation capacity, the source of feedstocks, and economic forces. Ideally, a fuel-cycle analysis would reflect the interaction of

regulatory, economic, and supply considerations. An important parameter is the total volume of fuel that is sold. When evaluating the effect of using an alternative fuel, the implicit assumption is that the alternative displaces gasoline. Such a displacement would require a one-for-one economic elasticity. However, if alternative fuels captured market share, through economic or regulatory forces, additional gasoline would be available for sale. The effect of alternative fuel use in California could achieve the following effects:

- Displace gasoline sales
- Provide additional gasoline which could reduce the price of gasoline and stimulate demand
- Increase the supply of oil and put pressure on oil prices

Such price-elasticity issues have a more significant effect on global fuel production. In California, fuel demand is fairly inelastic and stationary emissions are largely driven by regulatory considerations.

Emissions for marginal alternative fuel production and gasoline displacement were calculated for fuel-cycle activities in the SoCAB. The marginal emission values were estimated adjusted according to Table 3-4. The net result of the marginal analysis is that NO_x emissions amount only to tanker ship and truck emissions in the SoCAB. All other NO_x emissions are either controlled by RECLAIM or are associated with fuel production out side of the SoCAB. NMOG emissions correspond to fuel storage and distribution activities as well as power production for EVs.

Table 3-4: Adjustments for Marginal Fuel-Cycle Emission Analysis in the SoCAB, 2010

Fuel	Marginal Analysis Assumptions
Diesel	Zero emissions for phase 3.
Reformulated diesel, LPG	Same as diesel. Add emissions associated with additional refinery energy use (mostly electric power).
Methanol from natural gas, biomass	Produced outside of the South Coast. Phases 1 through 4 do not result in SoCAB emissions.
Methanol from LFG	Credit for reducing NMOG emissions from flaring or power generation. No NO _x credit for eliminating IC engine.
Natural gas for refineries	Zero emissions except for pipeline transmission emissions in phase 5. Emissions associated with pipeline leakage do not increase with increased throughput.
EV, power for refineries	83% generated out of basis. NO _x would be zero for electric power generation.

3.4 Petroleum Fuels

Diesel and LPG are produced from crude oil. These fuels, along with gasoline and other refinery products, share the same crude oil feedstock and therefore the same extraction and feedstock distribution paths (LPG, however, can also be produced from natural gas). Table 3-5 summarizes the 8 phases for conversion of crude oil to diesel and reformulated diesel.

Table 3-5: Diesel Production and Distribution Phases

Phase	Process	Emission Sources
1	Extraction	Heaters, pumps, fugitive
2	Transport	Pipeline (pumps), ships (engines), fixed roof storage tanks
3	Refining	Fugitive emissions, refinery heaters
4	Site storage	Refinery tanks
5	Transport to bulk storage	Pipeline (pumps & fugitive)
6	Bulk storage	Floating roof diesel tanks
7	Transport to local station	Tanker trucks (engines & fugitive)
8	Local station distribution	Underground tanks, refueling vapors, spills

3.4.1 Crude Oil Extraction

Crude oil for refineries in the SoCAB is produced from offshore and underground wells in the southern coast and San Joaquin Valley. Heavy crude from Kern County represents a large share of this product. Oil is also imported by tanker from Alaska and overseas. Table 3-6 shows the assumptions used for geographically allocating emissions to petroleum extraction and transport.

Table 3-6: Petroleum Extraction for SoCAB Use

Feedstock Location	% of Volume
Average	
South Coast (SC)	9
California (CA)	29
Alaska (U.S.)	31
Singapore (ROW)	21
ROW	10
Marginal	
ROW	100

California processes about 1.8 million barrels of crude oil per day. In 1992, 50 percent of this oil was produced in California; 45 percent was imported from Alaska; and the

remaining 5 percent was imported from foreign sources. Crude oil in California is primarily a heavy variety that is extracted by steam injection. New oil sources in the state are limited and prospects for new offshore production are unlikely. California's imports of foreign crude oil have not been large because several refineries have been modified to run efficiently on Alaska North Slope oil. CEC projects increased competition for Alaskan oil with an increase in demand in the western U.S. (PADD V) and declining Alaskan production. Allocation of crude oil production and refinery emissions to the SoCAB depends on whether an incremental gallon of gasoline or the average gallon of gasoline is considered.

Significant fraction of crude oil is produced in the SoCAB, marginal emissions associated with oil production in the SoCAB are estimated to be near zero. Refineries in the SoCAB operate at capacity and demand for additional diesel could be met by importing additional finished diesel. Oil production is estimated to not change with additional demand for diesel fuel as additional product may be imported to California or refinery operations may be modified slightly to produce more diesel and less gasoline.

This assumption does not suggest that the mix of California to imported oil should remain invariant under all conditions, merely that moderate changes in fuel demand will not shift the mix of crude oil sources. The mix of crude oil could change with changing oil prices. If oil prices dropped substantially, for example, more costly oil production in California could be reduced. Crude oil production techniques depend on the demand for oil. Increased use of more energy intensive techniques such as enhanced oil recovery would correspond to higher petroleum prices. The trend in California is to extract more oil through thermally enhanced oil recovery (TEOR). This report does not attempt to predict a change in oil feedstocks or changes in production techniques over the scenarios in this study.

3.4.2 Crude Oil Transport

Oil is transported to the refineries using two primary methods: pipelines and tanker ships. Pipeline emissions result from the pumps that move the oil through the pipelines. Tanker ship emissions are produced by the propulsion and auxiliary engines, which operate on heavy fuel oil. Table 3-7 shows the estimated mix of crude oil and finished petroleum product imports to California. This mix of locations would represent the average oil production mix for California. However, as discussed previously, an increase in diesel demand due to additional diesel consumption related to fuel switching (rather than a drop in prices) is estimated to result in no change in oil import emissions.

Table 3-7: Petroleum Transport for Average SoCA

Transport Process	Location	One Way Distance (mi)
Oil pipeline	South Coast (SC)	20
Oil Tanker	Alaska (U.S.)	1976
	Singapore (ROW)	7,650
Product tanker	Singapore (ROW)	7,650
Marginal		
Product tanker	Singapore (ROW)	7,650

3.4.3 Oil Refining

A variety of fuels are produced by oil refineries in the SoCAB. Products from refineries include several grades of gasoline, diesel, kerosene (jet fuel, heating oil, No. 1 Diesel), LPG, heavy oil, petroleum coke, sulfur, and asphalt. Energy inputs to refineries include crude oil, electric power, natural gas, gasoline blending stocks such as alkylate (high octane components such as iso-octane), and oxygenated compounds such as methanol, MTBE, and ethanol. The specifications for fuel in California have been changing over the years with sulfur reductions in diesel, reformulations of gasoline, low aromatics and equivalent diesel, and reductions in the use of MTBE. At the same time, emissions from refineries in the SoCAB have been declining steadily. The combination of feedstocks, products, and emissions makes allocating emissions to refinery products difficult.

As a first order estimate, there are no marginal emissions associated with producing more conventional diesel or LPG in a refinery. Several possibilities exist for adjusting refinery operation for changes in fuel output. If gasoline demand were reduced, it is likely that imports of finished gasoline would simply be reduced. Increased diesel demand at the expense of gasoline sales could be met by increasing the mix of diesel products that are imported to the SoCAB or adjusting refinery operations to produce more diesel. Analyzing the effect of changing the shift in refinery products would ideally be accomplished by a linear programming (LP) model that optimizes all of the refinery streams for an optimal economic and fuel specification output. Such LP analyses are not readily available for the displacement of gasoline with diesel.

Emissions from oil production in the SoCAB are expected to reduce over the next 20 years with the following measures:

- NO_x controls on refinery fluid catalytic cracking units
- Emission controls on off shore oil production
- Emission controls from refinery flares
- Carbon absorption, refrigeration, and incineration of fugitive hydrocarbons
- Emissions controls from bulk terminals

3.4.3.1 Diesel

If a significant amount of gasoline output were replaced with diesel, the operation of some energy intensive processes such as reforming and alkylation would be reduced with a net reduction of energy for refining. Such a displacement of emissions would result in the reduction of some refinery heat energy inputs with a reduction in combustion emissions. Total NO_x emissions from refineries would not be affected by a change in combustion emissions as refinery NO_x is under a cap through the RECLAIM program. NMOG emissions from combustion sources would however be reduced if fuel combustion were reduced due to a reduction in gasoline output and an increase in diesel output. As shown in Section 4.3, combustion NMOG emissions represent a smaller share of NMOG sources within oil refineries than do fugitive NMOG emissions. Variations in throughput have little impact on fugitive emissions.

Producing reformulated diesel would also affect refinery operations. Reformulated diesel will contain less sulfur and may also have a higher cetane index. Removing additional sulfur beyond current levels could be accomplished with severe conventional hydrotreating. The effect of producing reformulated diesel was estimated to be reflected by a change in sulfur from 150 ppm to 20 ppm for on road diesel. MathPro performed an LP model analysis of such a change in diesel fuel formulation (MathPro 1999). The results of the model reflected a change in energy inputs to the refinery that are discussed in Section 4.3. The model shows primarily an increase in electric power demand by the refinery with a small increase in crude oil imports. Emission impacts were estimated to correspond to the generation of power and combustion of additional refinery fuel.

3.4.3.2 LPG

Producing additional LPG was estimated to have zero marginal emission impacts from refineries in the SoCAB. The marginal uses of LPG are selling the product as a fuel or use as a refinery fuel or feedstock. Selling additional LPG for vehicle use would displace LPG sales to other customers and also displace LPG as a refinery fuel where it might be replaced with natural gas. Oil refineries may burn propane if the demand for it as a home heating or vehicle fuel is low. However, higher market prices (demand) would probably divert propane for use as a vehicle fuel (refineries would burn natural gas as a replacement). California imports a significant quantity of LPG. This LPG comes from natural gas processing facilities in Canada and the southwest United States. Some LPG is also imported from refineries in Utah. Future demand for LPG could be so high that marginal demand must come largely from natural gas liquids. However, given the opportunities for displacing LPG from refinery use, and the source of current LPG, this study assumes refinery-based and natural-gas-based LPG production.

3.4.4 Diesel Storage and Distribution

After diesel is produced in a refinery, it is stored in bulk tanks and distributed to fueling stations in tank trucks. Emissions resulting from the storage of petroleum and petroleum fuels consist of two main types: fugitive and spillage emissions. Fugitive emissions are hydrocarbon emissions that escape from storage tanks, pipes, valves, and

other sources of leaks. These emissions are generally greater for gasoline than diesel due to its higher vapor pressure.

The low vapor pressure of diesel has generally resulted in limited requirements on vapor recovery from storage and fueling equipment. The vapor pressure from diesel is so much lower than that of gasoline, that the uncontrolled diesel vapor losses are less than 10 percent of gasoline emissions with 95 percent emission control (see Section 4.9).

Vapor losses primarily occur when tank trucks are filled at the bulk terminal, unloaded at the fueling station, and during vehicle fueling. Spillage during vehicle fueling is also a significant source of emissions.

3.4.5 LPG Storage and Distribution

The fuel-cycle steps for LPG parallel those for diesel. LPG is stored and distributed in pressurized tanks as shown in Table 3-8.

Table 3-8: LPG Production and Distribution Phases

Phase	Process	Emission Sources
1	Extraction	Heaters, pumps, fugitive
2	Transport	Pipeline (pumps), ships (engines)
3	Refining	Refining process emissions
4	Site storage	Refinery tanks
5	Transport to bulk storage	Tanker truck
6	Bulk storage	Pressurized tanks
7	Transport to local station	Tanker trucks (engines & fugitive)
8	Local station distribution	Above ground tanks

3.5 LPG from Natural Gas

LPG is produced when liquids are extracted from natural gas. Marginal emissions in the SoCAB are zero since processing of LPG occurs in Canada or the Southwest states.

Fugitive emissions from gas production are discussed in Section 4.3.

The emissions rate for fugitive losses was determined from the annual emissions divided by annual production. Based on this data, fugitive losses in the United States represent 0.8 percent of total throughput. Fugitive losses were allocated to natural gas and LPG. The allocation to LPG was 3 percent, which is proportionate to the LPG content in natural gas from the well. Marginal leakage is likely low. Gas sweetening plants produce fugitive losses of heavy glycols. These emissions translate to less than 0.2 g/100scf. Methanol is used in drying systems for local compressors. The volume of methanol is negligible.

LPG is shipped in 30,000 gal rail cars. The fuel is transferred to 30,000 storage tanks either by pumping from the rail car or by 10,000 gal tanker trucks. Fuel is delivered to local service stations in 3,000 gal trucks where it is stored in 1,000 gal tanks. If LPG use for vehicles were to increase, the capacity of local delivery trucks and storage tanks would also increase.

3.6 Fuels from Remote Natural Gas

Synthetic diesel and other synthetic liquid fuels are formed from a three-step process (known as the Fischer-Tropsch [FT] process) which converts coal, biomass, or natural gas to liquid fuels. It is an attractive air quality option to conventional fuels because it contains no sulfur or aromatics and has a higher cetane number. This study considers only synthetic diesel from natural gas because it is the most economically attractive option.

As a result of this process, the fuel cycle for synthetic diesel at the upstream end is similar to compressed natural gas, and at the downstream end resembles diesel fuel. Table 3-9 shows the steps associated with FTP production and distribution.

Table 3-9: Synthetic Diesel Production and Distribution Phases

Phase	Process	Emission Sources
1	Extraction	Compressors, fugitive
2	Transport	Natural gas pipeline (compressors & fugitive)
3	Conversion	Fugitive emissions, vent gas combustion
4	Site storage	Fixed roof tanks
5	Transport to bulk storage	Tanker ships
6	Bulk storage	Floating roof tanks
7	Transport to local station	Tanker trucks (engines & fugitive)
8	Local station distribution	Underground tanks, refueling vapors and spillage

Methanol, like synthetic diesel, can be produced from a variety of feedstocks. Most methanol in the world and all of the methanol used in California as a vehicle fuel is made from natural gas. The conversion process typically used, called steam reforming, is similar to the process used to make synthetic diesel, but uses different catalysts, temperatures, and pressures. The upstream fuel cycle is similar to compressed natural gas. Fuel distribution for methanol consists of bulk storage terminals and transfer systems similar to those for gasoline. The steps for methanol production and distribution are shown in Table 3-10.

The following discussion covers the extraction and transport of remote natural gas for FTD and methanol production. Then the details of FTD and methanol production are discussed followed by a discussion of fuel transport and distribution.

Table 3-10: Methanol from Natural Gas Production and Distribution Phases

Phase	Process	Emission Sources
1	Extraction	Compressors, fugitive
2	Transport	Natural gas pipeline (compressors & fugitive)
3	Production	Fugitive emissions, vent gas combustion
4	Site storage	Fixed roof tanks
5	Transport to bulk storage	Pipeline (pumps & fugitive)
6	Bulk storage	Floating roof tanks
7	Transport to local station	Tanker trucks (engines & fugitive)
8	Local station distribution	Underground tanks, refueling vapors and spillage

3.6.1 Remote Natural Gas Production and Transportation

Both synthetic diesel and methanol have been produced from natural gas outside the United States. Remote locations are the likely sources of natural gas for FTD and methanol in the future.

Natural gas is recovered and collected from oil and natural gas fields. The gas is then transported by pipeline to processing facilities, which are usually located near the gas field. For commercial natural gas, the gas is processed to remove propane, butane, moisture, sulfur compounds and CO₂. However, for FTD and methanol production, CO₂ in the gas improves the efficiency of the process.

Excess natural gas from oil production operations is a likely FTD feedstock and in some instances methanol. Utilizing natural gas in this manner can eliminate flaring. Flaring natural gas can be a safety problem and flaring the gas contributes to CO₂ emissions.

When flared gas is used as a feedstock, no CO₂ emissions from the natural gas feedstock or end product fuel are attributed to the FTD or methanol product. If natural gas is extracted from locations that are not associated with oil fields or natural gas that would be reinjected into the oil well is used as feedstocks then CO₂ related to the natural gas is attributed to the FTD or methanol fuel.

Table 3-11 shows the natural gas transport distances and mix of diverted flared gas and new gas that was assumed for the scenarios in this study. These assumptions affect fuel-cycle energy and global CO₂ emissions. Twenty percent of natural gas feed is assumed to be associated with flared gas in Scenario 1. Flared gas is a large potential resource for fuel production. Many oil companies and some countries such as Nigeria have instituted policies to eliminate natural gas flaring. In Scenario 2, no credit for flared gas is attributed to FTD or methanol production with the assumption that the credit for flaring could be equally attributed to oil production.

Table 3-11: Natural Gas Transportation Assumptions for FTD and Methanol Production

Scenario	1	2	3
Flared Gas Feedstock	20%	0%	20%
Natural Gas Transport Distance (mi)	200	200	100
Compressor Engines	55% reciprocating 45% gas turbines	55% reciprocating 45% gas turbines	50% reciprocating 50% gas turbines

Many methanol plants are currently operating and under construction. With the apparent reduced use of MTBE, production capacity may exceed demand. Some methanol plants could be converted to produce FTD so the feedstock assumptions for the year 2010 are the same.

3.6.2 Synthetic Diesel Fuel Production

Synthetic fuels can be produced from the catalytic reaction of CO and hydrogen. The Fischer Tropsch (FT) process is one process that has been developed for fuel production. In recent years, developments in catalysts have allowed for the production of fuels in the diesel boiling point range. Synthetic diesel and Fischer Tropsch Diesel (FTD) are categorized together as all approaches for producing synthetic diesel are conceptually similar and result in the same emissions impact in California.

The FT process was originally developed in Germany in the 1920s to produce diesel from coal. FT plants are also operating in South Africa to make synthetic gasoline from coal. The FT process has three principal steps. First, a feedstock must be converted to synthesis gas, a mixture of carbon monoxide and hydrogen. Potential feedstocks include coal, biomass, and natural gas. A catalytic reactor converts the synthesis gas to hydrocarbons in the second step. The mixture of hydrocarbons consists of light hydrocarbons and heavier waxes. The majority of the hydrocarbons are saturated. In the third step, the mixture of hydrocarbons is converted to final products such as synthetic diesel fuel.

The FT process consists of three conversions:

1. Feedstock to a synthesis gas, a mixture of CO and hydrogen
2. Synthesis gas to hydrocarbons by use of a catalytic reactor
3. Hydrocarbons to the final products, like synthetic diesel

Now FT plants are currently being constructed to use remote natural gas as a feed stock. FT fuels can potentially be produced from renewable sources such as biomass. Production options are discussed in more detail in Section 4.4.

FT diesel fuel can be transported in conventional product tankers. Bulk storage, product blending, truck delivery, and local product dispensing can be accomplished with existing infrastructure. If pure FT diesel fuel is sold as a separate product, refueling

stations will need to reallocate their inventory of local storage tanks or install additional storage and dispensing equipment.

FT diesel is likely compatible with existing dispensing equipment and vehicle fuel systems. However, fuel compatibility issues have not been widely documented. Some fuel compatibility problems were identified when low aromatics diesel fuels were introduced in California. Problems appeared to occur on older model diesel engines with a specific type of fuel system.

Major oil companies are supporting the development of FT fuels or gas to liquids (GTL) products. Shell, Exxon, Texaco, and ARCO have built or are planning to build production facilities. Oil Companies own many of the natural gas fields in the world and are interested in finding a market for the fuel. Exxon included an article describing its GTL technology in their 1998 publication for shareholders which illustrates their interest in the technology.

FT fuels are attractive to oil companies since they improve the quality of diesel and make use of their natural gas resources. These fuels are also attractive since they can be used in existing vehicles.

FT fuels will become more widely available as more facilities are constructed to take advantage of low cost remote natural gas. The growth of the market may depend on the price of oil. Since the cost of producing FT fuels does not drop significantly with a drop in the price of oil low oil prices have hindered the commercial production of FT diesel. FT fuels will likely be blended to produce high cetane, low aromatic diesel before they are sold as pure clean fuel alternatives. The blending approach allows for a build up of production and bulk storage capacity. If a demand for pure FT fuels develops, the infrastructure will be in place.

3.6.3 Methanol Production from Natural Gas

California methanol mostly comes from Canada, with a smaller amount coming from Texas. Since transportation of natural gas from Texas is more expensive, as it usually comes by rail rather than ship, it was not considered here. We have also assumed that all the natural gas feedstock comes from Canada, and that the methanol is transported in Phase 4 from Canada to the South Coast by tanker ship.

Advances in methanol production technology will result in greater yields from steam reforming. New plants may also be built with combined steam reforming and partial oxidation. The more efficient technologies are reflected in Scenario 3.

3.7 Methanol from Biomass

There is also considerable interest in producing methanol from biomass. Two biomass feedstocks for methanol were considered. In one case landfill gas is processed into

methanol in the SoCAB. In another case, a gasifier operates on agricultural waste, wood waste, and energy crops in the Central Valley. Tables 3-12 and 3-13 show the assumptions for methanol production from biomass. Sufficiently large production volumes were assumed for biomass-based methanol production in California, so that the fuel can be transported to Los Angeles by pipeline. The pipeline options would be much more cost effective than trucking the fuel. The impact on the results of the study is that a bulk storage facility is assumed in Los Angeles, and trucking emissions are the same as those for other liquid fuels.

Table 3-12: Methanol from Biomass Gasification Production and Distribution Phases

Phase	Process	Emission Sources
1	Extraction	Harvest equipment
2	Transport	Trucks
3	Production	Fugitives, compressor engines, purge gas combustion
4	Site storage	Onsite tanks
5	Transport to bulk storage	Pipeline (pumps & fugitive)
6	Bulk storage	Floating roof tanks
7	Transport to local station	Tanker trucks (engines & fugitive)
8	Local station distribution	Underground tanks, refueling vapors and spillage

Table 3-13: Methanol from Landfill Gas Production and Distribution Phases

Phase	Process	Emission Sources
1	Extraction	Landfill collection pipes
2	Transport	Compressors
3	Production	Fugitives, purge gas combustion
4	Site storage	Onsite tanks
5	Transport to bulk storage	None
6	Bulk storage	None
7	Transport to local station	Tanker trucks (engines & fugitive)
8	Local station distribution	Underground tanks, refueling vapors and spillage

Landfill gas is a source of biomass energy that is used primarily to generate electric power. Biomass is converted to gas in landfills as the organic material is exposed to moisture and bacterial /fungal decomposition. The organic material is converted to approximately 60 percent CO₂ and 40 percent on a mass basis. Trace levels of hydrocarbons, sulfur-containing compounds and chlorinated compounds are also produced. Landfill gas is either flared or used to generate electricity. Other uses of landfill gas include methanol and hydrogen production.

Methanol has not been produced from biomass for use in California. A landfill gas to methanol project was planned for construction in Southern California but permitting issues prevented the project from going forwards (Wuebben).

Hydrogen Burner Technology (HBT) has a contract with the SCAQMD to develop a hydrogen production system based on the partial oxidation of LFG. Several landfill sites have been considered as possible sites for hydrogen production. The interest in hydrogen production indicates that alternatives to flaring and power generation are of interest to landfill operators.

Landfill gas is continuously exiting from the landfill either as uncontrolled losses, flared gas, or combusted gas for power generation. When LFG is converted to methanol, one of these pathways is interrupted. The question of marginal emissions is important for LFG as the alternative uses of LFG vary considerably. LFG is generally not vented in California and even in rare instances where it might be vented, crediting methanol production with these emission reductions does not reflect the marginal impact of the methanol production facility. The emissions impacts of producing using LFG from flared gas and IC engines are discussed below. Emission levels are quantified in Section 4.

3.7.1 Flared LFG

Flaring LFG results in emissions of NMOG, CH₄, NO_x, CO, traces of PM, and CO₂. Since the gas is primarily CH₄ and CO₂, NMOG emissions are low. Flares operate at relatively low temperatures so NO_x emissions are also relatively low. LFG is derived from biomass. The biomass consists of paper, food waste, wood waste, and other organic materials. The carbon is derived from CO₂ that was recently removed from the atmosphere. Therefore, flared LFG has zero net CO₂ associated with it. This CO₂ is counted as biomass CO₂ in this study.

3.7.2 Electric Power from LFG

Many landfills generate electric power from LFG. LFG is combusted either in IC engines or gas turbines. Producing electric power has both advantages and disadvantages for landfill operators. Noise from IC engines had resulted in complaints from citizens that have caused IC engines to be shut down and the LFG to be flared again. In the 1980's landfills were able to secure contracts to sell electric power for around \$0.10/kWh which provides for attractive economics for power generation. With electric power deregulation, the market price for power can vary from \$0.01 to \$0.03/kWh. This reduced price may not cover the cost of operating the LFG-to-power facility; however, landfills may continue to generate power as a means for disposing of LFG. Some facilities are integrated with sewage treatment plants, which have a high demand for electric power. Developments in the market for electric market make it unclear whether generating power from LFG will remain an economically attractive option. Therefore, some electric power capacity could be converted to methanol production.

The sulfur and chlorine containing compounds, while only present in ppm levels, present difficulties with emission control equipment and in some cases lead to corrosion of engines and turbines. NO_x control from LFG power generation equipment is limited. Lean burn IC engines experience operational problems as LFG has a much lower

heating value than natural gas. Catalytic NO_x control (SCR) is also not feasible with LFG without gas cleanup as the sulfur and chlorine compounds degrade the catalyst. Therefore, NO_x emissions from LFG power generation equipment are higher than other sources of electric power.

If an LFG electric power source were converted to methanol operation, the actual NO_x from the engine would be eliminated or largely reduced as the methanol reformer emits very little NO_x. However, it is likely that the NO_x from the engine is either part of an electric utility's RECLAIM mix or that the excess NO_x credits would be traded with other stationary users. Consequently, the net NO_x reduction due to replacing an IC engine or turbine with a methanol production facility is much lower than the difference between the emissions from the engine and the methanol facility. For example, an IC engine could stop operating. A small portion of its NO_x credits could be transferred to a new methanol production facility and the balance of the NO_x could be used by an electric utility to increase power generation capacity in the SoCAB.

If LFG that was formerly used in an IC engine is converted to methanol, the net CO₂ differs from the flared LFG case. Reducing LFG electric power will result in an increase in electric power output from other sources. The new power generation mix is assumed to be the "actual marginal" power mix for the SoCAB for constant time of day power output. This mix power generation mix does not differ substantially from the power generation mix for vehicle as the majority of the actual marginal power generated in the SoCAB is from new natural gas fired units.

4.0 Emissions from Fuel Production and Distribution Processes

This section includes emissions from feedstock extraction, fuel production, and distribution. The emissions sources are covered roughly in order from extraction through distribution with some overlap. Section 4.1 reviews emission rates from equipment used in transporting feedstocks and fuel and in processing operations. Energy usage rates for transportation equipment are also discussed in Section 4.1.

Fuel production emissions and energy inputs are covered in Section 4.2 through 4.8. The allocation of energy use to product fuels is discussed while fuel production processes have a minor or no effect on marginal NMOG or NO_x emissions in the SoCAB, they are still analyzed as they affect global CO₂ emissions. Fuel processing is defined as the conversion of feedstock material into end use fuel, or fuel production Phase 3. Feedstock input requirements also relate to feedstock extraction requirements in Section 4.1. LPG liquefaction is included Phase 3. Several fuels are processed from a combination of feedstocks and process fuels. Oil refineries and gas treatment plants produce multiple fuel products. Many production facilities import or export electricity and excess heat energy can be exported to other facilities,

Section 4.9 discusses emissions from fuel storage and distribution. These represent the most significant sources of marginal NMOG emissions. Section 4.10 discusses toxic emissions. Since toxic emissions are not measured as frequently as criteria pollutants, these emissions are primarily available from other data sources than those in Section 4.1 through 4.9. Toxic hydrocarbon emissions are estimated as a fraction of NMOG.

Several approaches have been taken towards determining fuel-cycle emissions. Perhaps the simplest approach is to estimate the energy required for each step of the fuel-cycle. Then, "emission factors" can be multiplied by the energy use rate (Jenkins 1979, Unnasch April 1990). There are several negative aspects of relying entirely on this approach. Primarily, energy use expressed in Btu/gal of fuel (or Btu/Btu fuel) is many steps removed from the actual fuel-cycle-processing step.

For example, consider a diesel deliver truck with 7,800 gal of fuel traveling a 50-mi round trip route. A diesel truck fuel consumption of 5 mi/gal is expressed in energy terms as 0.0014 Btu/Btu based on lower heating values (Table 2-1). Expressing all of the fuel processing steps in energy terms allows for a convenient comparison amongst different fuel-cycle emission studies. The emissions in this study are estimated from more fundamental principles. In the case of fuel delivery trucks, a constant mileage is assumed for all fuel types and emissions are calculated from the g/mi emissions and truck fuel capacity to yield g/gal of delivered fuel.

The energy in Btu (HHV) per unit of fuel produced is tracked with the fuel-cycle emissions. Lower heating values are only used to estimate vehicle fuel consumption and are not mixed with higher heating values anywhere in this study.

Emission rates from fuel production equipment are estimated from published emission factors, other emissions data, and emission requirements from local and federal rules. In

the strictest sense, an emission factor might be considered to be an energy specific emission rate, in g/gal fuel for example, that represents a wide range of equipment and is weighted according to equipment inventory, usage pattern, and other parameters. The term emission factor implies inventory wide applicability and is reserved for published emission rates.

Emissions depend on the location of equipment and the prevailing (and prior) emission standards. Vehicles and combustion equipment in the SoCAB are and will continue to be subject to the strictest emission controls.

SCAQMD limits are as stringent or more so than NSPS and NESHAPS standards. Table 4-1 shows NO_x limits on combustion sources in the SoCAB. Boilers and gas turbines have been subject to Best Available control technology (BACT) requirements since the 1980s. All equipment installed since that time would meet NO_x levels consistent with Rule 474. More recent installations will need to meet stricter NO_x limits under Rule 1134. NO_x levels of 9 ppm can only be met with Selective Catalytic Reduction (SCR) and actual emissions with SCR are one-half of the limit.

Emission limits under Rules 474, 1110, 1134, and 1146 are expressed in ppm. These were converted to lb NO₂/MMBtu using a fuel factor of 8740 dry scf/MMBtu for natural gas and 9220 dry scf/MMBtu for diesel fuel. These emissions are expressed in lb/Mwh or g/hp-hr for the energy consumption assumptions shown in the table.

4.1 Fuel Extraction, Transportation, and Processing Equipment

Several types of equipment are used repeatedly throughout the estimation of fuel-cycle emissions. For example, diesel powered tanker trucks are used to move diesel, LPG, and methanol fuels from storage locations. Natural gas engines and gas turbines compress natural gas and are used in a variety of fuel industry applications. These engines are used to transmit natural gas feedstock to oil refineries, FT diesel, methanol, and electric power plants. This section summarizes the emissions and estimated usage rates for various types of equipment. The usage rates are related to assumptions for different scenarios.

4.1.1 Engine Emissions

Table 4-2 summarizes the emission and performance characteristics of natural gas turbines used for natural gas transmission, prime movers. Table 4-2 shows estimate of current and future emissions for turbines operating in the SoCAB, California, and the United States. Turbines operating outside of North America are assumed to emit at 1990 United States levels.

Emissions in Table 4-2 are shown in g/bhp-hr. These are converted to g/100scf of natural gas transmitted with usage rates discussed later and the calculation approach in Section 4.4.

Table 4-1: Summary of SCAQMD NO_x rules

Rule 474 — Fuel Burning Equipment — Oxides of Nitrogen								
Emission Source	Non-Mobil Fuel Burning Equipment						Steam Generating Equipment	
Heat Rate (MBtu/hr)	555 to 1,785		1,786 to 2,142		>2,143		>555	
Fuel	Gas	Oil	Gas	Oil	Gas	Oil	Gas	Oil
NO _x Emissions (ppmvd @ 3% O ₂)	300	400	225	325	125	225	125	225
(lb/MMBtu)	0.37	0.52	0.28	0.42	0.15	0.29	0.15	0.29
Rule 1109 — Emissions of Oxides of Nitrogen for Boilers and Process Heaters in Petroleum Refineries								
Emission Source	Boilers and Process Heaters in Petroleum Refineries							
NO _x (lb/MMBtu)	0.03							
Rule 1110.2 — Emissions from Stationary Internal Combustion Engines (gaseous- & liquid-fueled)								
Emission Source	Stationary Internal Combustion Engines							
Energy Consumption (Btu/bhp-hr)	8000							
NO _x Emissions (ppmvd @ 15% O ₂)	36							
(lb/MMBtu)	0.121							
(g/bhp-hr)	0.44							
Rule 1134 — Emissions of Oxides of Nitrogen from Stationary Gas Turbines								
Emission Source	Simple Cycle	Simple Cycle	Simple Cycle No SCR	Simple Cycle	Simple Cycle No SCR	Combined Cycle No SCR	Combined Cycle	
Unit Size (MW)	0.3 to 2.9	2.9 to 10	2.9 to 10	>10	>10	>60	>60	
Energy Consumption (Btu/hp-hr)	13,000	13,000	11,000	11,000	11,000	6,000	6,000	
NO _x Emissions (ppmvd @ 15% O ₂)	25	9	14	9	12	15	9	
(lb/MMBtu)	0.093	0.0337	0.052	0.0337	0.044	0.056	0.0337	
(g/hp-hr)	0.55	0.20	0.26	0.17	0.22	0.15	0.092	
(lb/MWh)	0.90	0.59	0.77	0.50	0.65	0.45	0.27	
Rule 1146 — Emissions of Oxides of Nitrogen for Industrial, Institutional, and Commercial Boilers and Process Heaters								
Emission Source	Industrial, Institutional, and Commercial Boilers and Process Heaters							
NO _x (lb/MMBtu)	0.037							

Table 4-2: Natural Gas Turbine Emissions

Turbine Location	SoCAB		CA, U.S.	
Year	1993	2010	1993	2010
Energy rate (Btu/bhp-hr)	11,000	11,000	11,000	11,000
Emissions (g/bhp-hr)				
NO _x	0.4	0.17	1.7	1.0
CO	0.83	1.0	0.83	1.0
CO ₂	599	599	599	599
CH ₄	0.17	0.2	0.17	0.2
NMOG	0.01	0.01	0.01	0.01
Data Source	Huey	EE ^b	Huey	EE

^a NSPS for NO_x is 1.39 g/bhp-hr, SCAQMD Rule 1134 requirements are equivalent to 0.1 to 0.5 g/bhp-hr.

^b Engineering estimate. BACT for gas turbines will result in 0.03 g/bhp-hr. Newer gas turbines without SCR will have low NO_x configurations

Based on a population profile of gas turbines used as natural gas prime movers (Huey 1993) and emissions data for individual makes and models of gas turbines (Urban 1980 and Fanick 1988), the energy consumption to energy produced (energy rate) for gas turbines is estimated to be 11,000 Btu/bhp-hr. However, the range of energy rates for gas turbine prime movers can vary from 10,000 to 13,000 Btu/bhp-hr.

The current NO_x emission estimate for gas turbines located in the SoCAB is based on SCAQMD Rule 1134 (Emissions of Oxides of Nitrogen from Stationary Gas Turbines) and an estimate of the types of gas turbines in the region. Because the NO_x limit set forth in Rule 1134 varies according to control technology and rated power output, the NO_x emission factor is an average emission factor for several types of gas turbines with varying power output and control technologies. The future NO_x emission factor for gas turbines in the SoCAB is based on the emissions from the best available control technologies for gas turbines.

The current NO_x emission factor assigned to gas turbines located outside the SoCAB (CA and the U.S.) is based on a gas turbine prime mover population profile and emissions data for those gas turbines. Assuming a greater use of NO_x controls, the future NO_x emission factor assigned to CA and the U.S. will be lower than the current NO_x emission factor.

Current CO and HC emissions for all turbines in the United States are based on a population profile of the gas turbine prime movers (Huey 1993) and emissions data (Urban 1980 and Fanick 1988) for uncontrolled gas turbines. By assuming a greater use of NO_x control technologies in the future, CO and HC emissions for all future turbines should increase slightly. For very lean operation, CO and HC emissions increase as NO_x emission decrease. The emissions data also show (and emission factors represent) that methane emissions makes up over 90 percent of the THC emissions from a gas turbine.

Table 4-3 summarizes the emission and performance characteristics of natural gas reciprocating engines used for natural gas transmission, prime movers. Table 4-4 estimates current and future emission rates for engines operating in the SoCAB, California, and the United States. Engines outside of North America are assumed to emit at the 1990 U.S. level.

Table 4-3: Natural Gas Reciprocating Engine Emissions

Engine Location	SoCAB		CA, U.S.	
Year	1990	2010	1990	2010
Energy rate (Btu/bhp-hr)	8,000	8,000	8,000	8,000
Emissions (g/bhp-hr)				
NO _x	2	0.44	6	2
CO	2.65	3	2.65	3
CO ₂	463	463	463	463
CH ₄	4.42	5	4.42	5
NMOG	0.45	0.5	0.45	0.5
Data Source	Huey	EE ^b	Huey	EE

^a SCAQMD rule 1110.2 requirements are equivalent to 0.34 to 0.61 g/bhp-hr.

^b Engineering estimate.

Table 4-4: Off-Road Equipment Emissions

Equipment Type	1990 Diesel 101-175 hp	2010 CA Diesel	1990 Gasoline 4-stroke 40-100 hp	2010 Gasoline
Energy rate (Btu/bhp-hr)	9350	9350	11,200 ^a	11,200
Fuel consumption (g/bhp-hr)	220	220	244	250
Emissions (g/bhp-hr)				
NO _x	11	7	3.0	3.0
CO	3.4	3.4	235	235
CO ₂	700	700	758	758
CH ₄	0	0	0	0
NMOG	1.1	1.1	8.25	6.6 ^b

^a 20 percent increase in energy consumption with gasoline.

^b 20 percent reduction in mass emissions with RFG.

Sources: Kreebe 1992, A. D. Little.

Based on a population profile of reciprocating engines prime movers (Huey 1993) and emissions data for individual makes and models of engines (Urban 1980 and Fanick 1988), the energy consumption for engines is estimated to be 8,000 Btu/bhp-hr. This value can range from 6,000 to 10,000 Btu/bhp-hr.

Population profiles of reciprocating engine prime movers indicate that, the majority of these engines are lean-burn with relatively few being stoichiometric or rich-burn

engines. The emission factors assigned to reciprocating engine prime movers are associated with lean-burn engines. Uncontrolled lean burn engines do not operate sufficiently lean to provide significant NO_x reductions. All new lean burn engines sold in North America are configured for low NO_x emissions.

NO_x emissions outside the SoCAB (CA and the U.S.) are estimated to be 6 g/bhp-hr, which is based on an engine prime mover population and emissions profile. NO_x emissions for an uncontrolled lean-burn prime mover range from 10 to 12 g/bhp-hr, whereas the emissions for a controlled lean-burn prime mover are about 1 to 2 g/bhp-hr (Huey 1994). This study assumes that roughly half of the engine prime movers outside the SoCAB are controlled.

NO_x emissions for the SoCAB and future NO_x emissions for CA and North America are estimated to be 2 g/bhp-hr, which is equivalent to a controlled lean-burn engine. Future NO_x emissions for engines located in the SoCAB are estimate to 0.48 g/bhp-hr, based on SCAQMD Rule 1110.2 (Emissions from Stationary Internal Combustion Engines).

Current CO and HC emissions for all engine prime movers in the U.S. are based on a population profile of the gas turbine prime movers (Huey 1993) and emissions data (Urban 1980 and Fanick 1988) for uncontrolled engines and are consistent with AP-42 factors. Future CO and HC emissions for all engines in the U.S. should increase slightly due to the greater use of NO_x control technologies. Generally CO and HC emissions increase as NO_x emission decreases. Similar to gas turbines, the emissions data also show that methane emissions makes up over 90 percent of the VOC emissions from an engine.

4.1.2 Biomass Collection Equipment

Fuels and feedstocks are transported and distributed by a variety of equipment including trucks, trains, and marine vessels. Emissions from fuel or material transport were determined from emission rates and equipment usage factors that take into account distance traveled and cargo load. The emissions and use factors for the relevant fuels are discussed for each transportation mode. Several types of biomass are potential feedstocks for fuel production. Such feedstocks include agricultural wastes, wood waste, and purpose grown energy crops. Potential energy crops include poplar and euclyptus. feedstock transportation requirements for a combustion of agricultural material and forest residue were used to estimate fuel usage in this study.

Emission factors from an ARB study on farming equipment are shown in Table 4-4 (Kreebe 1992). The study considered a range of equipment power that did not vary substantially (for the overall emission factor) in NO_x. The most prominent size range for agricultural equipment is used in this study. Typical energy consumption values are assumed for diesel equipment and increased by 20 percent for gasoline.

Evaporative emissions were estimated from ARB's study on off-road emissions. For the 40 to 100 hp category of agricultural equipment, evaporative emissions were 550

lb/unit per year of which 98 percent were running losses. Running losses in the ARB study were based on the EMFAC emission factor for uncontrolled automobiles. The study indicates 5248 operating hours per year and 32,906 gallons per year of fuel use for 70-hp equipment. The evaporative emissions are then 7.6 g/gal. An additional 4.6 g/gal was added for uncontrolled fueling emissions from Section 4.2. Evaporative emissions for RFG- and diesel-fueled equipment were adjusted for the vapor pressure in proportion to the mass emissions in Section 4.2.

Usage rates for farming equipment in Table 4-5 are combined with fuel production yields in Table 4-6. The study shows diesel energy as a proxy for petroleum fuels and other energy inputs. Table 4-5 shows the energy components for diesel in greater detail. ARB's off-road emission study (Kreebe) indicates that 10 percent of agricultural equipment is gasoline-fueled. Energy requirements for biomass hauling are estimated for a truck, with a fuel economy of 5 mpg, hauling 37,000 lb of biomass over a 50-mile round trip. The energy requirements per unit of product fuel are based on the process yield considerations in Section 4.2.

Table 4-5: Energy Input for Biomass Collection

Energy Input	Forest Material		Urban Wood Waste	
	gal/ton	Btu/lb Biomass	gal/ton	Btu/lb Biomass
Diesel equipment	2.2	120	1.2	70
Gasoline equipment	—	15	—	8
Electricity	5 kWh	0.0004 ^b	5 kWh	0.0002 ^b
Diesel transport	—	37	—	37

^a The split between gasoline and diesel is estimated on a Btu/lb basis from Kreebe.
^b kWh/lb

Table 4-6: Equipment Energy Use for Biomass Production

Product	Yield ¹ (lb/gal)	Scenario	Energy consumption (Btu/gal)		
			Diesel Tractor	Gasoline Equipment	Diesel truck
Methanol	15 lb/gal	2	4830	540	555
Methanol	12.2 lb/gal	3	3928	439	451

The California Energy Commission (CEC) and DOE have explored numerous approaches for producing biomass feedstocks. Two studies included estimates of energy inputs for wood based feedstock in California.

4.1.3 Truck Emissions

Tanker trucks are used to haul fuel for local delivery as well as longer range transportation for fuels that are not locally available. Table 4-7 shows the emissions from heavy-duty trucks. ARB's EMFAC model estimates truck emissions for the average truckload and weight. These estimates are based on engine dynamometer results in g/bhp-hr which are converted to g/mi. The conversion factor implicitly takes into account driving patterns and vehicle loads that probably do not reflect those of tanker trucks. The Los Angeles County Metropolitan Transportation Authority has tested numerous heavy-duty vehicles on a chassis dynamometer. A series of tests were run on a truck whose emissions were tested at gross vehicle weights (GVW) ranging from 25,000 to 55,000 lb (Wool). Tank truck emissions are based on these chassis dynamometer tests. More stringent emission controls should result in lower NO_x emissions for heavy-duty trucks. The 1990 NO_x estimate corresponds to an engine that emits 5 g/bhp-hr. A 2 g/bhp-hr (or lower) NO_x standard will apply to heavy-duty vehicles by 2010. Therefore, year 2010 NO_x for all trucks in the United States are projected to be 40 percent of current levels.

Table 4-7: Heavy-Duty Truck Emissions

Truck Type	1990 75,000 GVW	2010 75,000 GVW
Fuel economy (mi/gal)	5.0	5.0
(Btu/mi)	27,560	27,560
Emissions (g/mi)		
NO _x	23.5	9.4
CO	11.0	11.0
CO ₂	2,000	2,000
CH ₄	0	—
NMOG	1.7	1.7
Particulate	1.2	0.6

Source: LACMTA data, adjusted for load (Wool).

Table 4-8 shows the load carrying capacity of tanker trucks. The gallon carrying capacity depends on the liquid fuel density since the truck must meet axle weight requirements. The values shown in the table are typical for current fuel deliveries. For reformulated diesel, it is unlikely that the load will be varied to take into account small differences in fuel density.

Table 4-9 shows the distances for hauling fuels by tanker truck with the assumption of a central Los Angeles fueling location. The distances are based on a typical round trip to the appropriate fuel storage site. Petroleum fuels are stored in proximity to oil refineries in the SoCAB with many storage terminals along the coast (Wilmington, El Segundo, etc.). Methanol is currently stored at a chemical terminal in San Pedro. Some finished fuels are trucked further distances. Future biomass derived fuels may also be trucked into Los Angeles from outside the area.

Table 4-8: Tank Truck Load for Local Distribution

Fuel	Truckload (gal)	Fuel Density (lb/gal)	Fuel Weight (lb)	Truckload Energy (10⁶ Btu LHV)
Diesel	7,080	7.2	51,000	6,550
LPG	10,000	4.2	42,000	3,470
LPG	3,000	4.2	12,600	1,040
FTD	8,000	6.4	51,400	6,110
M100	7,800	6.6	51,500	2,940

Table 4-9: Tank Truck and Pipeline Distance for Fuel Distribution

Fuel	Application	One-Way Distance (mi)	Location
Diesel	Local delivery	25	SoCAB
M100 Natural gas	Local delivery	25	SoCAB
M100 LFG	Local delivery	25	SoCAB
M100 Biomass	Local delivery	25	SoCAB
LPG	Local delivery	25	SoCAB
LPG	Transport to distribution	25	SoCAB

4.1.4 Marine Vessel Emissions

Crude oil and finished fuels are shipped in tanker ships. Tankers are powered by steam turbines as well as low speed diesels. The most prominent propulsion system for ocean going tankers is a two-stroke diesel (Burghardt).

Table 4-10 shows emissions from typical marine diesel propulsion engines. The NO_x emissions are comparable to or slightly higher than those from uncontrolled truck engines. Fuel consumption in g/bhp-hr is quite high. One reason for the higher fuel consumption is the higher calorific value of the heavy fuel oil used in marine diesels combined with combustion advantages of low speed operation and higher compression ratios. Fuel consumption of marine diesels has dropped from 140 down to 120 g/bhp-hr over the past two decades (compared to 215 g/bhp-hr for a diesel engine on the EPA transient cycle). NO_x levels depend on engine load over the ships operating profile. Emission factors that take into account a ship's operating profile and are expressed in g/kg fuel shown in Table 4-11.

Tankers capacity is measured in dead weight tons (DWT) which includes the total carrying capacity of the ship. The load efficiency indicates what fraction of the total cargo capacity is actually carried. Fuel consumption decreases with larger tanker size. Tanker carrying load is measured in ton-miles. For marine applications distance is measured in nautical miles (2000 yards) and speed is measured in knots or nautical miles per hour. For this analysis, crude oil, FTD, and methanol are shipped in

Table 4-10: Emissions from Marine Diesel Engines

Emission Source	Two-Stroke Diesel, Bunker Fuel	Four-Stroke Diesel, Bunker Fuel
Energy rate (Btu/bhp-hr)	5890	6086
BSFC (g/bhp-hr)	120 to 140	120 to 140
Emissions (g/bhp-hr)		
NO _x	13.4	10.4
CO	0.15	0.75
CO ₂	448	463
CH ₄	—	—
NMOG	0.6	0.2

Source: Arthur D. Little

Table 4-11: Emissions and Use Factors for Tanker Ship Operations

Emission Source	150,000 DWT tanker 1990 Diesel Motor
At sea use factors	
Fuel Consumption (kg/ton-mi)	0.0018
Load efficiency	0.95
Fuel	Bunker fuel
Energy Content (Btu/kg)	40,350
At sea emissions (g/kg fuel)	
NO _x	70
CO	1
CO ₂	3,300
CH ₄	—
NMOG	4

Sources: Melhus, Bremnes

Emission Source	Tug boats and ships
In port use factors	
Port transit time (h)	2
Hotelling, pumping (h)	30
Tugboat operation (h)	8
Fuel use (kg/visit)	7,716
(kg/DWT)	0.051
Fuel	diesel
Energy content (Btu/kg)	42,560
In port and tugboat emission factors (g/kg fuel)	
NO _x	37
CO	13.9
CO ₂	3200
CH ₄	—
NMOG	6.9

Sources: AP-42, Kimble

150,000 DWT tankers. Fuel consumption for tankers also varies with tanker speed and ocean conditions. Data from several sources (ARB 1990) indicate that the fuel consumption for a modern tanker is about 1.8 kg/1000 ton-mi. This fuel consumption is based on a round trip, carrying ballast on the return trip.

Tanker ships also produce emissions while in port. Auxiliary engines operate to produce electric power and tugboat maneuver the tanker into port or to the oil unloading platform. In port time for tanker ships is generally as short as possible in order to maximize use of the tanker. In port operation time and fuel consumption were estimated from information included in and ARB workshop on marine emissions. Tugboat fuel consumption is estimated from hours of tugboat operation and tugboat fuel consumption curves. NO_x emission factors are lower for port operations than those for at sea operations because the engines operate at lower load, use lighter diesel oil, and a different mix of engines.

Table 4-12 shows the distances traveled by tanker ships. The capacity of the tanker in gallons of product per DWT is also shown. Tankers carry about 95 percent of their weight capacity as cargo with the balance being consumables and ballast. Thus 95 percent of a short ton results in 288 gal of methanol per DWT (2000 lb/ton/6.6 lb/gal × 0.95 capacity).

Table 4-12: Overview of Waterway Transportation

Route to Los Angeles	One Way Distance (naut. mi)^a	Cargo	Capacity (Gallons/DWT)
Vancouver, BC	570	Methanol	288
Valdez, AK	770	Crude Oil	247
Singapore	7,700	Crude Oil	247
Singapore	7,700	Methanol	288
Singapore	7,700	FTD	260

^aNautical Mile = 1.136 mile = 2,000 yards.

Table 4-13 shows the marine transportation distance assumptions. The percentages represent the weighted average of the shipping distance that corresponds to the locations indicated in the table. Tanker travel distance in the SoCAB is taken to be 26 nautical miles. Several studies have considered the appropriate distance to include for marine vessel inventories (Port of Los Angeles). The SCAQMD boundaries include a 32 nautical mile section towards Venture County and a 18 nautical mi section heading to the South. Other studies have drawn a 88 nautical mile radius from shore or a similar shape out past San Clemente Island. Tanker ships probably reduce their power and coast when entering port that would lead to lower emissions along the coast. A relatively shorter (26 mi) tanker travel distance was assumed for this study while tanker emissions are not adjusted for reduced load. Assuming a longer distance and lower emissions would yield a similar result.

Table 4-13: Partition of Marine Transport Distances^a

Location	Vancouver	Singapore, Indonesia	Alaska
Mileage Allocation			
SoCAB	26	26	26
CA	544	272	180
U.S.	430	215	23
ROW	0	7710	3110

^a One way distance, nautical miles

4.2 Refinery Emissions

A variety of petroleum products are produced from crude oil. Refineries produce gasoline, diesel, kerosene/jet fuel, LPG, residual oil, asphalt and other products. A variety of co-feedstocks, including natural gas, electricity, hydrocarbons from other refineries, and MTBE and other oxygenates, complicates the analysis of fuel-cycle emissions. Different crude oil feedstocks, gasoline specifications, and product mixes also complicates the picture for refineries.

Determining the emissions from the production of petroleum products involved the following approach. The SCAQMD emissions inventory includes emissions from oil production, refining, and distribution. These emissions are broken down by type, e.g. fugitives from valves and flanges. Emissions from base year, 1996, is based on emission use fees from stationary sources. These values were the basis for determining emissions, on a gram per total amount of petroleum production basis. However, these emissions need to be allocated to the various refinery products in order to reflect the energy requirements for producing different fuels.

The output from refinery model was used to determine the energy inputs required to produce different gasoline, diesel, and other petroleum products. Refinery combustion emissions were allocated to gasoline, diesel, and LPG in proportion to the energy requirements for refinery units. The refinery model was also used to determine changes in refinery energy needed to produce reformulated gasoline. This approach results in the average emissions from refineries.

Emissions from refinery units in the model were allocated to the petroleum products produced by each refinery unit. For example, all of the combustion emissions associated with the diesel hydrodesulfurization unit are attributed to diesel fuel. Table 4-14 shows the allocation of crude oil energy input and imported energy to gasoline, diesel, kerosene (same as jet fuel), and LPG.

Table 4-14: Allocation of Product Output and Energy Consumption for Refineries

Product	Product Output Btus (%)	Combustion Fuel Allocation (%) ^a	Energy Inputs (Btu per Gallon of Product)		
			Natural Gas	Electricity	Total Energy Ratio (%)
Conventional					
Gasoline	56	69	551	0.75 kWh	119.6
Kerosene (jet)	17	41	348	0.15 kWh	108.7
Diesel	25	48	482	0.45 kWh	112.9
LPG	2	17	197	0.019 kWh	107.3

^a The combustion energy allocation applies to emissions and energy use expressed on g/gal of gasoline basis and determines the emissions allocated to the specific fuel on a g/gal basis.

SCAQMD Inventory

The SCAQMD emissions inventory provides insight into emissions from oil production, refining, and distribution in the four county SoCAB. Refineries and oil producers submit emission fee forms annually to the SCAQMD. Emissions for these forms are determined from either published emission factors or from source testing. These values make up SCAQMD's base year inventory.

Most of the emission rates are determined from calculations that depends on equipment type and throughput using SCAQMD and AP-42 emission factors. Other emissions are determined from source testing.

The SCAQMD inventory is determined for average days as well as summer and winter days. The summer inventory was examined in this study since it is intended to represent conditions for maximum ozone formation. The summer inventory may not be representative of the petroleum industry since refineries operate at fairly constant capacity and are not affected by seasonal activities. The summer inventory may also be adjusted for increases in temperature and higher evaporative emissions. Higher RVPs in the winter might cancel out the temperature effect, however, crude oil breathing losses will be higher.

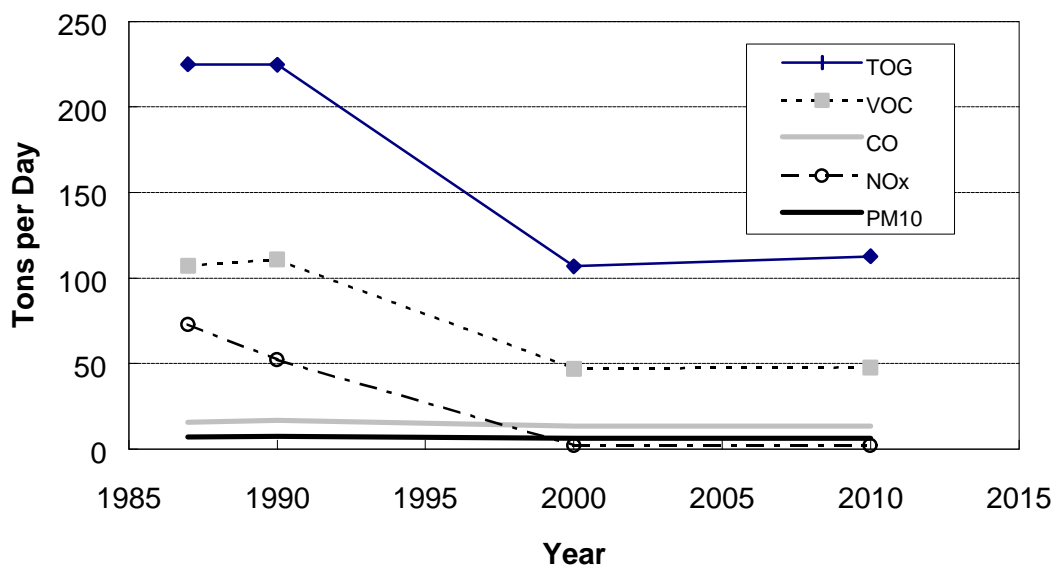
Table 4-15 shows the SCAQMD TOG and VOC summer inventory for the years 1987, 1990, 2000, and 2010 for the SoCAB (SCAQMD 1997, III-B). The inventory of TOG, VOC, NO_x, CO, and PM₁₀, is also shown in Figure 4-1. Since the sources emit hydrocarbon emissions, TOG corresponds to total hydrocarbons and VOC corresponds to NMOG. All of the values in the table were extracted from the 1997 inventory document with the exception of the refinery product throughput (19,500,000 gal/day) which was determined from and ARB inventory printout. Emissions for 1990 represent a baseline from which future year emissions are projected.

Table 4-15: SCAQMD Inventory for Oil Production, Refining, and Marketing

Source Category	VOC			
	1987	1990	2000	2010
Fuel Combustion				
Oil & Gas Production	0.80	0.66	0.56	0.56
Petroleum Refining	1.68	1.39	1.33	1.33
Petroleum Process, Storage & Transfer				
Oil & Gas Extraction	38.70	43.30	11.68	11.70
Petroleum Refining	23.61	21.79	9.08	9.16
Petroleum Marketing	40.76	40.99	22.29	22.81
Other	1.60	2.62	2.00	2.24
Total	107.15	110.75	46.94	47.80

Source: SCAQMD 1997.

Figure 4-1. SCAQMD Inventory for Oil and Gas Production, Refining, and Marketing



Source: SCAQMD 1997.

Table 4-16 shows the VOC emissions from oil production on g/gal basis. The refining and production values in Table 4-16 are shown on a total refinery emissions per gallon of gasoline basis. These emissions must be allocated to gasoline (46 percent for production and 55 percent for refining as shown in Table 4-16).

Table 4-16: NMOG Emissions From SCAQMD Oil Production and Refinery (g/gal)^a

Emission Source	1990	2010
Oil production	0.449	0.277
Oil refining	0.929	0.812

^a Total emissions per gallon of gasoline.

Energy inputs for producing reformulated diesel were estimated from an EMA study on low sulfur diesel formulations. LP model runs, performed by MathPro, estimated the energy inputs for an oil refinery shown in Table 4-17. Only the energy inputs that changed with fuel formulations are shown. Diesel production was 35 kbbbl/day for all of the model runs. 80 kbbbl/day of gasoline as well as other products are also produced by the refinery. The energy inputs represent a relatively small fraction of the energy in the product diesel. Taking the difference between the 20 and 150 ppm sulfur case, energy inputs to the refinery are -0.2 kbbbl/day of crude oil and fuel and 18 MWh of electric power. The net difference in energy input is 4000 Btu/gal of diesel or about 3 percent of the fuel's energy content. While sulfur reduction in diesel fuel requires capital equipment, the energy and emission impacts are relatively small.

Emissions associated with reformulated diesel production were estimated to correspond to those for generating electric power for the additional energy input less a credit for the reduction in fuel input to the refinery. Emissions for producing electric power are discussed in Section 4.8.

Table 4-17: Model Energy Inputs for Producing Reformulated Diesel

	150 ppm Diesel^a	20 ppm Diesel^b
Inputs		
Crude Oil (kWh/day)	147.3	147.1
Isobutane (kbbbl/day)	1.5	1.4
Fuel (kbbbl/day)	12.7	12.8
Electric Power (MWh/day)	776.6	794.6
Net (Btu/gal) ^c	837,600	841,400
Outputs		
Diesel (kbbbl/day)	35	35
Sulfur (tons/day)	137	142

^a MathPro Case 8.

^b MathPro Case 9a.

^c Electricity is counted as 9000 Btu/kWh.

Source: MathPro.

4.3 LPG Processing from Natural Gas

The study evaluated the emissions attributable to LPG production. These emissions can be associated with the process for converting raw natural gas into market dry gas since LPG components are removed from the gas as waste products. The propane (over 97 percent), ethane, butane, and methane are removed from natural gas during the extraction process. In 1998, 561 million metric tonnes of gas were withdrawn from oil and gas wells. Of this, approximately 400 million tonnes were produced as dry gas, while 14 million tonnes of LPG were extracted. The LPG produced has been calculated by examining the DOE Energy Information Administration's inventories of gas withdrawn, portions removed during production, and portions removed during extraction. Methane, light hydrocarbons, and other gases are used for pressurizing gas and are lost due to venting and flaring during production. In addition, hydrocarbons are removed during the liquid extraction process and fugitive losses occur. The EIA inventories show that only 29 percent of the extracted liquids is propane. Since this is the main component of LPG, the quantity of LPG produced is much less than the total hydrocarbons extracted.

The calculations estimated that emissions associated with the LPG production are proportional to the quantity of LPG produced. Thus 3.7 percent of the methane and CO₂ emissions during the production process could be accounted in an LPG fuel-cycle analysis. Although one could claim that the emissions are a result of natural gas production since LPG contains unwanted natural gas components, the marketability of LPG requires accountability for the emissions. It is also useful to note that without data to describe the exact losses due to each natural gas component at each stage of processing, it is difficult to calculate the specific emissions. However, it is sufficient to extrapolate from the masses of methane, NMOG, and LPG in the end products.

4.4 Synthetic Diesel Production

Natural gas is converted to synthesis gas by reforming the feedstock with steam and oxygen. Natural gas is the simplest feedstock to convert to synthesis gas since it is gas and does not need to be processed in a gasifier. This synthesis gas is over 90 percent carbon monoxide and hydrogen with traces of methane and nitrogen. The FT reactor uses iron or cobalt catalysts in a fluidized bed reactor. Excess heat from the FT reactor produces steam for the reformer. Additional thermal energy can be used to generate steam to produce electric power or provide other process heat requirements such as powering desalinization plants. Wax is converted to liquid fuels by reacting with hydrogen in the final step of the process. The energy ratio (fuel output/feedstock input) for a natural gas to FT diesel plant is about 56 percent (HHV basis). This value does not include uses for excess thermal energy.

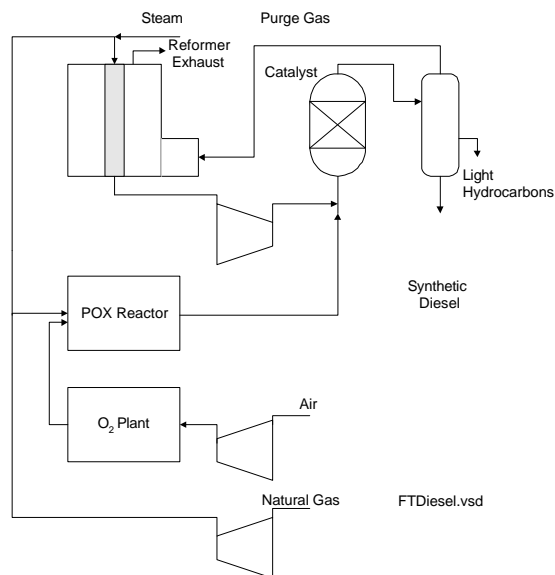
A FTD plant consists of the following processes:

- Synthesis gas production (reforming and partial oxidation)
- Catalytic hydrocarbon production
- Final product separation

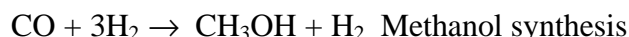
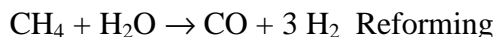
Emissions from FTD diesel facilities were estimated as either combustion emissions or fugitive emissions.

Understanding the configuration of synthetic fuels plants helps illustrate the fate of carbon and net CO₂ as well as combustion and compressor engine emissions. A synthetic fuels plant with a steam reformer and POX reactor is illustrated in Figure 4-2. A steam reformer converts steam and CH₄ to CO and hydrogen. An excess of hydrogen is produced with a steam reformer. The CO and hydrogen mixture flows over a catalyst where methanol or other fuels are produced. This reaction occurs at high pressures (30 atm) as equilibrium does not favor synthesizing methanol or hydrocarbons at low pressure. The synthesis gas may be recirculated several times over the catalyst or flow over the catalyst in a single pass (once through process). Recirculating the synthesis gas results in a higher fuel conversion rate. The power required to compress and circulate the synthesis gas is a significant energy demand. This power is provided by natural gas engines, electric motors powered by energy created at the plant or steam driven turbines. Excess synthesis gas contains hydrogen, since there is a stoichiometric excess, unreacted CO and CO₂, and CH₄ that was not converted in the reformer.

Figure 4-2: Process Components for Synthetic Fuel Production



Producing methanol or FTD from natural gas results produces a fuel with reduced hydrogen content compared to CH₄. (While methanol has four hydrogens per carbon, it can be considered a combination of CH₂ and H₂O for this discussion. Since the composition of the feedstock and fuel differ, a carbon balance must be used to determine the amount of CO₂ emitted from synthetic fuel production. This is simply illustrated by the overall reactions for a steam reforming methanol plant.



In practice, equilibrium and reactor volume considerations prevent all of the CO from being converted to methanol. In addition, some of the methane is not converted to CO and hydrogen. Converting CH₄ to fuels does however convert a significant fraction of the carbon in methane to fuel. A process is thus characterized by its energy efficiency, energy ration and carbon efficiency. The energy efficiency is the ratio of product output to all energy inputs to the facility (natural gas for reforming, natural gas for compressor engines and electric power). The product output can include fuel, electricity or steam that is exported to other facilities. The energy ratio is simply the fuel output divided by the natural gas input. The carbon efficiency is the carbon in the fuel divided by the carbon in the feedstock (not counting natural gas for compressors). Higher heating values are used to represent energy efficiency in the United States and lower heating values are used in Europe. Efficiency values in this report are identified at HHVs.

Combustion emissions from FTD and methanol plants are purged synthesis gas. Since the purge gas consists primarily of hydrogen, CO₂ and CO with low levels of CH₄ and ppm levels of HCs, NMOG emissions from reformers are extremely low. Emissions estimates for FTD production are shown in Table 4-18.

Steam reforming results in an excess of hydrogen for each mole of carbon. In steam reforming systems, the purge gas provides fuel to the reformer. Purge gas input to the reformer exceeds the energy requirements of the reformer for generating steam and the reforming reaction. Excess steam energy can be used to power compressors or generate electric power.

The subject of steam export and credits for steam exports is a key issue for fuel-cycle studies. Credit for steam production or electric power generation can be given for export steam. Several approaches exist for providing credits for excess process energy. The energy required to generate steam in a boiler from natural gas can be determined and used as a credit, primarily for process energy and CO₂. Also, the credit can be calculated in terms of energy required to generate electric power. Steam can only be exported to adjacent facilities the plant is collocated with an oil refinery or chemical plant that can utilize the steam. The subject of credits for excess steam can have a significant impact on the CO₂ balance. Steam is produced from excess process heat and by burning hydrogen and has a very low CO₂ emissions associated with it as the carbon

efficiency of methanol and FTD production is relatively high. If excess steam is credited with power generation from natural gas or coal, the resulting credit will increase the effective carbon efficiency of fuel production.

Table 4-18: FTD Processing From Natural Gas

Process	Syntroleum Process			
	No Steam Export		Steam Export	
Fuel Processing				
Steam export (Btu/gal)	0		32,200	
Energy ratio (%)	54		53	
NG feed (Btu/gal)	238,000		242,500	
(100 scf/gal)	2.31		2.35	
Emission Source	Fugitive	Vent	Fugitive	Vent
Emissions (g/gal)				
NO _x	0	0.1	0	0.1
CO	0	0.50	0	0.5
CH ₄	3	0.04	3	0.04
NMOG ^d	2	0.04	02	0.04

^aNG = Natural gas.

^bNMOG = Non-methane organic gases.

Source: ANL, Bechtel.

In this study, care was taken to identify power requirements within the fuel production facility. Compressors for gas circulation and oxygen plants require significant amounts of power. However, excess steam is still produced in some processes. FTD production results in more excess energy as the hydrogen to carbon content in the fuel is lower than that of methanol. After all power requirements in the production facility are taken into account, excess energy is provided a credit equivalent to electric power generation from natural gas. Essentially, a synthetic fuels facility can serve to coproduce fuel and electric power. Such designs have frequently been considered. The Coolwater coal gasification facility was almost converted to coproduce methanol and electric power in 1996.

Synthesis gas can also be produced through a partial oxidation (POX) process. Oxygen or air is reacted with natural gas to produce synthesis gas. The hydrogen to carbon ratio of the POX product gas is lower than that of a steam reforming process. An important advantage of the POX process is that the reforming process is simplified through direct contact of the POX products in the feed gas stream. Industrial POX processes generally use pure oxygen from an air separation plant; however POX operation with air is also possible. Operation on pure oxygen has the advantage of eliminating nitrogen from the gas stream. Nitrogen acts as a dilute that increases the requirement for compression recirculation, and catalyst volumes.

Steam reforming and POX plants can be combined as shown in Figure 4-2 or combination POX and steam reforming systems are also possible. Combining steam reforming and POX operation allows for the production of a synthesis gas that has an

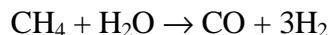
optimal ratio of hydrogen to CO to improve plant efficiency. The ratio depends on the fuel being produced and the process. Combined POX and steam reformer systems are referred to as autothermal reformers. (ATR).

4.5 Methanol Production from Natural Gas

4.5.2 Methanol

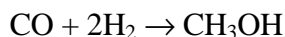
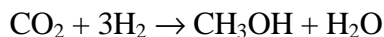
Methanol was first produced by heating wood and distilling the products. In 1913, methanol was produced by passing CO and H₂ over an iron catalyst. Currently, almost all of the methanol in the world is made by dissociating natural gas, primarily CH₄, into CO and H₂ with the addition of steam or oxygen (referred to as steam reforming or partial oxidation, respectively). Some CO₂, CH₄, and light hydrocarbons are also produced. This gas mixture produced through steam reforming or partial oxidation is called synthesis gas or syngas. Methanol is produced under pressure in a reactor by catalyzing CO and CO₂ with H₂. Crude methanol produced by the reactor is then refined into chemical grade methanol.

Steam reforming of natural gas yields synthesis gas for methanol production through the following chemical reaction:



The products that are formed by the gasification of coal or biomass (CO, CO₂, H₂, H₂O and CH₄) can also be processed into suitable feedstock for methanol synthesis. Likewise, CO₂ and H₂ can be the feedstock for methanol production.

Methanol that is produced by catalyzing CO and CO₂ with H₂ is formed through the following reactions:



Process energy requirements for methanol production from natural gas shown in Table 4-19.

Table 4-19: Methanol Processing From Natural Gas

Process	Steam Reforming						Combined Partial		
	Current			Advanced			Oxidation		
Fuel Processing									
Electricity use (kWh/gal)									
Energy ratio (%)									
NG feed (Btu/gal)									
(100 scf/gal)									
Combustion (Btu/gal)									
Emission Source	P.V.^b	D.V.^c	Reformer	P.V.	D.V.	Reformer	P.V.	D.V.	Vent
Emissions (g/gal)									
NO _x	0	0	2.94	0	0	1.36	0	0	0.28
CO	0	0	0.50	0	0	0.46	0	1	0.09
CO ₂	5	1	1,135	1	1	1,023	1	1	737
CH ₄	2.9	0	0.04	0.29	0	0.04	0.29	0	0.01
NMOG ^d	0.4	1.2	0.04	0.04	0.12	0.04	0.04	0.12	0.01

^aNG = Natural gas.

^bP.V. = Purge vent.

^cD.V. = Distillation vent.

^dNMOG = Non-methane organic gases.

Source: Bechtel

The partial oxidation process (POX) produces a more stoichiometrically optimum synthesis gas that is fed to the methanol reactor. In this process, oxygen reacts with methane to produce two moles of hydrogen per mole of CO. The POX reactor is exothermic and does not require combustion with air. Therefore, NO_x emissions from this process are negligible. Combining a POX plant with a steam reformer is a particularly advantageous process since the exothermic heat from the POX unit can be used as energy for the steam reformer. When available, adding CO₂ can enhance the efficiency of methanol production.

Energy consumption data for steam reforming and POX were obtained from several studies. Natural gas reformers are fueled with process gas left over from the methanol synthesis. This gas is primarily composed of hydrogen with CO, methane, CO₂, and methanol. Emission factors for natural gas were used to estimate NO_x, CO, methane, and NMOG emissions. CO₂ emissions are determined from a carbon balance. The difference between carbon in the natural gas feed and carbon in the natural gas product is carbon in the form of CO, hydrocarbon, or CO₂ emissions. Over 99 percent of this carbon is emitted as CO₂. POX process produces NO_x emissions since combustion with air does not occur. A small amount of pollutants are emitted from flaring purge gas.

Methanol plants can be either importers or exporters of electricity. Power generation emissions associated with net electric power were included with the fuel production emissions. Electricity demand for the POX process includes required energy for an oxygen plant.

The energy input for methanol production depends largely upon the production technology. In some cases, waste CO₂ (perhaps from an oil field), can be added to the feed stream to generate a CO/H₂ mixture that has a higher methanol yield.

The energy input for methanol production only affects global CO₂ emissions. The technology for methanol production facilities does not affect emissions in CA. Total CO₂ and hydrocarbon emissions are presented in the Methanex annual report. These emissions combined with the amount of methanol produced could provide a comparison to other estimates of methanol production emissions.

4.6 Methanol Production from Landfill Gas

Methanol can be produced from landfill gas through a steam reforming or partial oxidation process similar to the synthesis from natural gas feedstocks. Emission estimates for a landfill based methanol production facility are shown in Table 4-20.

Table 4-20: Landfill Gas from Biomass

Process	Steam Reformer	
Fuel Processing		
Electricity use (kWh/gal)		1.87
Energy ratio (%)		60.4
Feedstock (Btu/gal)		107,300
Feedstock (lb/gal)		2.22
Net combustion (Btu/gal)		38,000
		Process Gas
Emission Source	Vent	Combustion
Emissions (g/gal)		
NO _x	0	0.52
CO	0	1.7
CH ₄	0	0.7
NMOG	0.004	0.03

^aNG = Natural gas.

4.7 Methanol Produced from Biomass Gasification

Synthesis gas from coal gasification can also provide a feedstock for methanol production. Numerous coal gasification systems have been studied and many of these considered for methanol production plants. Table 4-21 shows energy inputs and emissions based on several methanol production studies. Distillation vent emissions are taken to be the same as those from natural gas to methanol facilities. Similar to the POX process, no air combustion occurs and exhaust emissions are minimal. CO₂ is

produced in a shift reactor or left over from methanol synthesis and emitted from a purge vent.

Table 4-21: Methanol Processing from Biomass

Process	IGT Fluidized Bed		Shell Entrained Bed	
Fuel Processing				
Electricity use (kWh/gal)		1.56		1.74
Production (kWh/gal)		0.79		0.67
Energy ratio (%)		52.4		64.7
Feedstock (Btu/gal)		123,057		99,663
Feedstock (lb/gal)		15.0		12.2
Net combustion (Btu/gal)		16,690		2,667
Emission Source	Vent	Process Gas Combustion	Vent	Process Gas Combustion
Emissions (g/gal)				
NO _x	0	0.76	0	0.12
CO	0	0.26	0	0.04
CH ₄	0	0.02	0	0.003
NMOG	0	0.02	0	0.003

Coproducing methanol and electricity provides an opportunity to balance the load from coal gasification systems. With this process, synthesis gas from the gasifier is passes over a methanol catalyst and the unreacted gas burned in a power plant. The Air Products LPMEOH process is particularly suited for once through type operations since a high methanol conversion can be achieved in a single pass through the catalyst. Biomass co-feedstocks such as sewage sludge have been considered as feeds for coal gasifiers but were not evaluated in this study.

4.8 Electric Power Generation

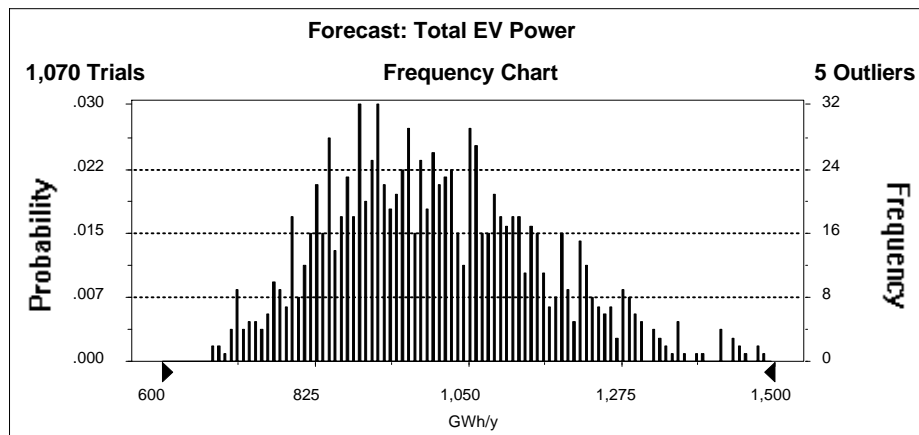
Two scenarios for electric power generation were developed to reflect future power plant additions and retirements. CEC modeled the mix of power generation by estimating the new power plants to have an adequate supply of resources for future demand levels. Since some fundamental changes have occurred in the electric industry, traditional resource planning methods were not used to develop the two scenarios presented in the study. The CEC's RAM³ Model was used to evaluate supply adequacy concerns.

Multisym™ model runs were done with and without EV loads to calculate the incremental emissions (pounds per MWh) for the year 2010. Incremental results are presented for each California air basin and for other large regions of the West.

³ Reliability Assessment Model developed by Albert Belostosky, Ph.D.

In order to determine the amount of electricity that electric vehicles may draw from power plants in the year 2010, many assumptions were made about the number of EVs that are expected to be connected to the grid, their operational efficiency and likely annual miles traveled. These assumptions were included in a simple probability model that calculates the effect of uncertainty on a range of predicted outcomes. Figure 4-3 displays results from many combinations of assumptions generated with this simple probability model. The results show that, under various combinations of assumptions, approximately 1,000 GWh is a reasonable estimate of energy needed by EVs statewide in 2010.

Figure 4-3. Projected Power Demand for EVs in 2010



This estimate of EV electricity consumption is divided among the California transmission areas designated within the Multisym™ model. These areas are (1) Northern California, which is basically the entire region north of Los Banos (19.0%); (2) Southern California, which is the major part of the state south of Los Banos (65.0%); (3) San Diego area (5.0%); (4) LADWP area (10.0%); (5) San Francisco Area (1.0%); (6) IID area, which we assume has negligible EV load.

This assessment was based on a profile that allocates about 95 percent of recharging load into the off-peak periods and 5 percent into the on-peak period.⁴ According to current EV-owner data received by CEC staff, owners are taking full advantage of time-of-use metered rates and recharging their vehicles mainly during off-peak hours. The same recharging profile was used in the CEC's 1995 study.

⁴ Electricity demand in California peaks in the afternoon and in this analysis, peak hours are from 11:00 a.m. until 6:00 p.m. and all other hours are assumed off-peak.

Two potential resource plan scenarios for the Western System Coordinating Council (WSCC) region in the year 2010 were used in the analysis.

The system adequacy implications of each resource plan were then evaluated using the CEC's RAM Model. If a transmission area was still resource short, additional generic combined cycles or combustion turbines were added to this area. The following is a brief description of each resource plan and how it was developed.

Resource Plan 1

Basically represents all of the expected resource additions and retirements identified from public resources and information available in the CEC. Each unit identified in the WSCC 10-Year Coordinated Plan Summary as a significant generation addition is included in the scenario. All of the 29 current and future siting case projects outlined in a January 29, 1999 draft CEC staff working document are included in this resource plan. The San Onofre Nuclear Generating Station is assumed to be out of the resource mix in 2010 under both scenarios. Additionally, 311MW of renewable projects with Public Interest Surcharge support are included.

Resource Plan 2

This resource plan is centered on the possibility that all the nuclear units in California (Diablo Canyon and San Onofre) may shut down by 2010. The retirement of Diablo Canyon is only part of the difference between this plan and the Scenario 1 resource plan. This Scenario 2 resource plan also includes a greater number of generation facilities that are assumed retired in California and in most cases replaced with new, more efficient capacity (at the same site). However, the net number of capacity additions under Scenario 2 is 857 MW less in 2010 than the Scenario 1 resource plan. Furthermore, the non-nuclear resource additions for the South Coast Air Basin area include an assumption that RECLAIM trading credit strategies and site/land limitations will restrict total allowable emissions and facility size.

Marginal emission results for the entire WSCC are presented by each air basin within California and for areas outside of California. Utilizing the Multisym™ model we are able to provide estimates of incremental emissions from power plants located within California. However, the emissions for regions outside of California are an estimated emission factor. These estimated emission factors depend on the fuel mix of the incremental energy produced in each area outside of California. Presently, CEC has not compiled adequate information on emissions factors for all resources located outside of California to provide similar Multisym™ results.

It should be noted that adding about 1,000 GWhs of energy demand throughout California in 2010 has a very small effect on the incremental results for the entire WSCC region under either scenario. In addition, existing steam boilers in the area are assumed to be retrofit by 2010 with additional emission control equipment in both resource plans. Existing generation outside of the SoCAB is not assumed to be retrofit with additional emission control equipment.

4.8.1 Power Generation Emissions

In the Scenario 1 Multisym™ results, the majority of incremental energy generated in California is from new gas-fired generation and the larger existing gas-fired power plants. The incremental emission factors shown in Table 4-22 for air basins in California are a mix of new combined cycle technologies and existing gas-fired steam boiler type power plants. Areas outside of California provide incremental energy from a mix of gas-fired (73 percent) and coal-fired generation (27 percent). The majority of this imported energy is gas-fired; however, the majority of these incremental emissions outside of California are from the coal-fired generation.

Scenario 2 Multisym™ results are similar to those using the Scenario 1 capacity expansion plan. The majority of incremental energy generated in California is from new gas-fired generation and the larger existing gas-fired power plants. However, in this scenario we assumed that both of California nuclear units are not in the resource mix. The resulting incremental emission factors, shown in Table 4-23, are slightly higher for most areas within California since existing gas-fired power plants are providing more incremental energy⁵.

The Scenario 2 results show that approximately 95 percent of the incremental energy from regions outside of California are gas-fired and about 5 percent is coal-fired. This lesser amount of imported incremental coal-fired generation is the reason for the lower incremental emission factors outside of California.

Differences between Resource Plans 1 and 2 results are most apparent within California air basins where new gas-fired power plants are located. For example, under Scenario 2 assumptions, there is more incremental generation from the Sacramento Valley and San Francisco Bay Area air basins because more new gas-fired resources are added to these locations. However, the out-of-state differences between Research Plans 1 and 2 tend to be more a function of which units the Multisym™ predicts to be forced out, rather than a result of new generation.

Moreover, these incremental results are similar to those results generated in the Energy Commission's 1995 EV Report and reported in the Acurex fuel cycle study. The principal difference is in the mix of incremental energy imported from areas outside of California. The majority of imported energy to meet a slight increase in off-peak demand tended to be gas-fired. Previously, a constant mix of gas, hydro and coal-fired generation from imported energy was assumed.

The fraction of imported power has a significant effect on marginal emissions in the SoCAB. In Resource Plans 1 and 2 about 21 percent of the power is generated in the SoCAB for purposes of evaluating marginal emissions from EVs, the NMOG emission factor is 5.4 tons/800 GWh or 0.006 g/kWh.

⁵ Existing generation outside of the South Coast Air Basin is not assumed to be retrofit with additional emission control equipment

Table 4-22: Power Generation Emissions, Resource Plan 1, 2010

Area	Generation GWh	NO_x (tons)	NO_x lbs./MWh	NMOG (tons)	NMOG lb/MWh	Carbon (tons)	Carbon lb/MWh
Mojave Desert	50.8	12.4	0.49	1.7	0.067	6.7	0.26
North Central Coast	39.2	13.4	0.68	0.6	0.031	5.1	0.26
Northeast Plateau	4.0	0.0	0.00	0.0	0.000	0.0	0.00
Sacramento Valley	26.3	2.2	0.17	0.8	0.061	2.8	0.21
Salton Sea	2.6	0.6	0.46	0.1	0.077	0.5	0.39
San Diego County	89.5	2.0	0.04	1.5	0.034	11.7	0.26
San Francisco Bay Area	148.8	46.9	0.63	3.1	0.042	21.6	0.29
San Joaquin Valley	178.2	4.7	0.05	4.0	0.045	20.1	0.23
South Central Coast	84.8	16.6	0.39	0.7	0.017	13.6	0.32
South Coast	168.0	49.7	0.59	5.3	0.063	47.2	0.28
California Total	792.1	148.5	0.37	17.8	0.04	129.3	0.33
Southwest	55.8		5.24		0.029		0.37
Northwest	9.7		2.73		0.036		0.39
Rocky Mountains	16.7		6.35		0.020		0.35
Nevada/Utah	104.8		2.64		0.040		0.39
Mexico	20.4		2.50		0.040		0.40
Outside California Total	207.4		3.63		0.04		0.38
WSCC Total	1000.5		1.05		0.043		0.34

Table 4-23: Power Generation Emissions, Resource Plan 2, 2010

Area	Generation GWh	NO_x (tons)	NO_x lb/MWh	NMOG (tons)	NMOG lb/MWh	Carbon (Tons)	Carbon lb/MWh
Mojave Desert	49.4	12.6	0.51	1.4	0.057	6.6	0.27
North Central Coast	38.1	16.8	0.88	0.4	0.021	6.5	0.34
Northeast Plateau	1.9	0.0	0.00	0.0	0.000	0.0	0.00
Sacramento Valley	52.3	5.6	0.21	1.1	0.042	5.9	0.23
Salton Sea	5.8	3.0	1.03	0.3	0.103	0.6	0.21
San Diego County	138.1	4.4	0.06	3.1	0.045	36.6	0.53
San Francisco Bay Area	157.1	25.4	0.32	3.8	0.048	95.1	1.21
San Joaquin Valley	132.6	4.0	0.06	3.2	0.048	15.3	0.23
South Central Coast	57.6	15.9	0.55	0.6	0.021	9.8	0.34
South Coast	163.8	32.0	0.39	5.4	0.066	41.3	0.28
California Total	796.6	119.7	0.30	19.3	0.05	217.7	0.55
Southwest	42.9		3.40		0.034		0.38
Northwest	4.7		2.50		0.050		0.40
Rocky Mountains	28.9		2.50		0.050		0.40
Nevada/Utah	108.8		2.50		0.050		0.40
Mexico	18.0		2.50		0.040		0.40
Outside California Total	203.4		2.69		0.05		0.40
WSCC Total	999.9		0.79		0.048		0.52

4.8.2 Electricity Distribution

Electricity distribution results in losses through the power lines. Typical transmission losses range from 3.5 to 13.5 percent. This value depends on the specific application. Transmission losses are built into the power generation requirements discussed in Section 4.8.1. CEC's electric power modeling runs took into account the average distribution losses for LADWP and SCE (around 9 and 7 percent, respectively).

Losses also occur during vehicle charging. The magnitude of these losses depend on the battery type and charging system. EV energy consumption is reported in terms kWh of electricity at the outlet; therefore the EV energy consumption includes charging losses. Actual energy consumption could vary with the type of EV charger and the state of battery charge.

Most facilities are currently being phased into RECLAIM, but are still subject to Regulation 11 or BACT, until they come into compliance with RECLAIM. Under RECLAIM, there are exemptions for municipal refuse fired facilities that are publicly-owned, landfill gas-fired and energy recovery facilities, and the cities of Burbank, Glendale, and Pasadena. The rest of the South Coast region will be subject to RECLAIM. Those facilities that are exempt from RECLAIM will still be subject to Regulation 11 rules or BACT.

4.9: Fuel Storage and Distribution

Marketing and distribution of fuels involve their storage, transport, and transfer to a vehicle. These steps are described as Phases 4 through 8 in Section 3. The storage and distribution of liquid fuels is similar and considered in Section 4.9.1. Section 4.9.2 considers emissions from gaseous fuels.

4.9.1 Liquid Fuel Storage and Distribution

Diesel, reformulated diesel, LPG, FTD, and methanol will be stored in bulk storage tanks, both at production facilities and at product distribution terminals. Emissions from marketing and distribution of fuels primarily consist of fugitive emissions, such as breathing losses, vapor transfer losses, and spills during fuel transfers.

Local Fuel Storage and Delivery — Liquid Fuels

This section describes the bulk storage and delivery of liquid fuels. Table 4-24 shows the emissions from bulk storage tanks based on the calculation technique in AP-42. The throughput is varied for current and future M100.

Calculated vapor emissions were used as the estimate for fuel product storage (production Phase 6). Fixed roof storage tanks are used for production facility storage for overseas methanol plants and presumably also FTD plants. The higher emission rates are reflected in Table 4-25. Production plant and terminal emissions for this study are shown in Table 4-25. Since these tanks represent a sizeable amount of emissions on an annual basis, vapor controls may be required. For Scenarios 3, a 90 percent reduction in emissions (reduction factor of 0.1) is assumed for methanol tanks in the

SoCAB except for diesel where it's a low vapor pressure might preclude vapor control requirements.

Table 4-24: Fugitive NMOG Emissions from Internal Floating Roof Storage Tanks

Fuel	Diesel	FT Diesel	M100	M100
RVP (psi)	0.03	0.04	4.63	4.63
TVP (psi)	0.02	0.02	3.50	3.50
Temp. (°F)	90	90	90	90
MW	130	120	32	32
Tank Capacity (bbl)	50,000	50,000	8,000	50,000
Tank Diameter (ft)	100	100	45	100
Tank Height (ft)	36	36	30	36
Throughput (bbl/yr)	600,000	600,000	100,000	600,000
Throughput (gal/day)	69,041	69,041	11,507	69,041
Turnover (day/tank)	30.42	30.42	29.20	30.42
Uncontrolled Emissions (lb/yr)	198	187	159	349
Emissions (g/gal)	0.0036	0.0034	0.0172	0.0063

Table 4-25: NMOG Emissions from Bulk Fuel Terminals

Fuel	NMOG Emissions (g/gal)	
	Plant/ Refinery	Bulk Terminal
Diesel	0.036	0.0036
LPG	0	0
FT Diesel	0.01	0.0036
M100	0.018	0.0063

Current M100 emissions are based on calculations for an 8000 bbl floating roof tank. The throughput includes both chemical and vehicle methanol demand. Future methanol emissions assume the same tank size and throughput as that of diesel.

Local Fuel Distribution — Liquid Fuels

This section describes the storage and distribution of liquid fuels at local service stations. These emissions consist of the following categories:

- Tank truck unloading spills
- Under ground tank filling — working losses
- Under ground tank breathing
- Vehicle fuel tank filling — working losses

Fuel is unloaded from a tank truck with vapor recover (referred to as Stage I). Most liquid fuel in California is stored in underground tanks. During the course of fuel storage, the vapor or ullage space in the tank expands and contracts with atmospheric pressure changes and fuel temperature changes. The fuel temperature remains almost constant in underground tanks. Fuel is dispensed to vehicles with a vapor recover hose system (Stage II vapor recovery).

The different stages of fuel distribution were observed to provide insight for this project. There are no significant differences in the unloading of gasoline or alcohol fuels. Fuel unloading at service stations is performed by the tank truck operator who may be an oil company employee or work for an independent company. Unloading is accomplished with appropriate precautions for safety and minimizing emissions. Fuel and vapor transfer hoses are connected from the storage tank to the truck. The truck carries its own fuel transfer hoses and an assortment of fittings for connection to the underground tank. After verifying the remaining tank volume with a dipstick measurement, the truck operator initiates the gravity fed unloading operation. When the fuel transfer is completed, the hoses are returned back to the tank truck. There is still a considerable volume of fuel in the fuel transfer hose (about 4-inch inner diameter). The truck operator disconnects the hose from the truck tank and drains the remaining fuel in the bottom of the hose into the underground storage tank by lifting the hose into the air and moving the elevated section towards the connection at the underground tank. The hose is then disconnected and stored on the truck. During several such fueling operations, about 250 ml of fuel was observed spilling out of the hose as it was placed back into its holding tube on the truck. It was estimated that the volume from spills is about 180 g for an 8000 gal fuel load or 0.023 g/gal (0.05 lb/1000 gal). While this quantity is based on casual observations, it provides some quantification of a small source that is not explicitly counted in the inventory. It is difficult to spill no fuel during hose transfers since the inner wall of the transfer hose is covered with fuel as indicated by hooks on some tanker trucks for drying clean up rags. An even smaller amount of fuel may remain on the hose surface and evaporate later.

Truck transfer is intended to be a no spill operation. Drivers are instructed to drain the hose into the tank before placing it back on the truck. Catch drains at the top of underground tanks would capture some spilled fuel if it dripped from the tank connection. However, some wet hose losses are inevitable. The thin layer of fuel in the hose will result in some drips and evaporation. It should be pointed out that the volumes used in this study are based on rough estimates and do not reflect a large sample. Furthermore, liquid spill volumes are difficult to measure.

Inventory emission factors

ARB determines emission factors from gasoline dispensing facilities (Asregadoo 1992). The emission sources are broken into the categories shown in Table 4-26. Each category has an emission factor for uncontrolled and controlled fueling operations. Spills from tank truck unloading are not explicitly accounted for; however, they may be implicitly included in an adjustment factor. Emissions from working losses and tank

breathing are based on a combination of ideal gas law calculations in AP-42 and ARB's certification testing results. The current document shows 0.7 lb/1000 gal for fuel spillage. All of the spilled liquid will evaporate from the concrete surface at service stations. Uncontrolled emissions are determined from the gas concentration in the tank ullage space.

Table 4-26: ARB Emission Control Factors for Gasoline Dispensing Facilities

Description	Control Factor (%)	Defect Rate (%)
Under ground tank working loss	95	0
Under ground tank breathing loss	90	0
Vehicle refueling vapor displacement	95	5
Vehicle refueling spillage	0	0

Since the values in this study will be compared to emission inventories it is important to understand how inventories are developed and how those values compare to this study. Emission inventories are based on the mix of controlled and uncontrolled sources and estimate of the number of operations with defective emission controls. Stage I and Stage II vapor recovery are considered to be 95 percent effective; so controlled emissions are 5 percent of the uncontrolled value. Breathing losses from underground tanks are estimated at 10 percent of the uncontrolled value if both Stage I and Stage II controls are in effect. No controls are assumed for spillage. The mix between controlled and uncontrolled service stations varies across the State. Some smaller operations have been exempt from Stage II vapor recovery requirements. Stage I vapor recovery is always used. In addition to reducing emissions, it returns vapor product to the refinery and provides for safer operations.

Statewide inventories are comprised of emission factors that are adjusted for malfunctions or failures in the vapor recovery system or defect rate. For example, emissions from vehicle refueling vapor displacement or working losses with 95 percent control and a 4 percent defect rate would be the following:

$$\text{Emissions (lb/1000 gal)} = 10 \times 0.96 \times 0.05 + 10 \times 0.04 = 0.88$$

The defect rate has a profound effect on the overall emission estimate and was incorporated into the vapor emissions in this study. Emission inventories include control factors that vary by year and also defect rates that vary by year. Since these numbers are not readily accessible at this time, distribution emissions were based on the assumptions shown in Table 4-26. The control factors and defect rates were applied to M100. The baseline uncontrolled emissions were then modeled from the fuel's vapor pressure and vapor molecular weight.

Future refueling emissions might be lower due to reduced Stage 2 failures with vacuum assist nozzles and other fueling equipment; however, the extent of such reductions if any has not been quantified.

Distribution emissions are estimated from the emission control assumptions in Table 4-26, and the fuel's properties. An underlying assumption is that the control effectiveness is equal for all fuels. There might be greater variation in control effectiveness for small volume fuel distribution (perhaps higher or lower) and underground tank breathing losses would depend upon the fueling station throughput. The number of vehicles per station will vary as more alcohol-fueled vehicles are introduced into the State. A total vehicle to fueling station ratio of about 2500 currently exists for gasoline-fueled vehicles. Many of these stations have multiple tanks. As alcohol-fueled vehicles are introduced, the ratio of vehicles to fuel tanks will be approach to the ratio for gasoline tanks. Therefore, differences in breathing losses due to differences in throughput will be small on a lb per day basis during an alcohol vehicle transition and would become negligible for a larger fleet of alcohol-fueled vehicles. Second order effects on breathing losses (per gallon) would depend on whether gasoline tanks are decommissioned if alternative-fueled cars displace gasoline-fueled cars. Given equivalent assumptions on emission control, distribution emissions depend on fuel vapor pressure and vapor molecular weight. Scenario 3 includes a downward adjustment by 50 percent of service station vapor losses to reflect reduced emissions from storage tank breathing and a potentially lower defect rate for Stage 2 control.

Vehicle Fueling Spillage

Service station fueling practices were also observed to evaluate vehicle fueling. The dispensers at numerous fuel stations were polled to determine the amount of fuel dispensed per fueling event. The amount of fuel dispensed ranged from one half to 18 gallons with an average of 8 gallons. The volume of fuel dispensed is important in determining emissions that depend on the number of fueling events rather than fuel volume. Various vapor recover nozzle types are used at service stations in California. At self-service stations, the vehicle driver dispenses the fuel. Most customers select the self-service option that results in a lower fuel price. While most vehicle operations are successful with little fuel spilled from the nozzle, occasionally a significant quantity of fuel is spilled. Fuel spills from vehicle refueling were evaluated by ARB (Morgester). This paper estimated spills from small drips as well as large refueler error type accidents. The average fuel spill size was estimated to be 0.42 lb/1000 gal. An API study estimated spill volumes at 0.31 lb/1000 gal.

Spill factors of 3.2, 0.87, and 0.87 g/gal were used for Scenarios 1, 2, and 3, respectively. The spill factors reflect ARB's new rules for vehicle refueling spillage.

The API study does not indicate an increase in spillage from self-service fueling and topping off. Spilled fuel evaporates completely and is counted as fugitive emission.

Spillage rates for other liquid fuels were based on the premise that the average spill volume remains constant. Several fuel stations were surveyed and an average gasoline fill volume of 8.8 gallons was observed. This is consistent with the 9.2 gal observed by Morgester. An increase in fuel tank capacity for alternative-fueled vehicles is expected, but not enough to completely make up for the reduction in energy content. Table 4-27 shows the estimated average fill volume for the fuels in this study. LPG is also shown for comparison. Since the fuels have different densities, the spill mass was adjusted for each fuel.

Table 4-27: Vehicle Fuel Spillage Parameters

Fuel	Average Tank Fill (gal)	Spill Volume		Spill Rate (g/gal)
		(ml/fill)	(ml/gal)	
Diesel, RFD	9	4.0	0.44	0.23
FTD	9	4.0	0.44	0.207
LPG	12	2.0	0.17	0.084
M100	9	4.0	0.44	0.211

Vapor space NMOG mass

Vapor emissions in this study are determined from modeled vapor concentrations. The fuel temperature used to determine vapor concentrations was selected to be consistent with ARB's inventory for fueling station emissions.

The vapor concentration in the tank vapor space is the basis for fuel transfer emission calculations in AP-42 and provides insight into the temperature conditions for vapor emissions. Vapor space concentrations are modeled to from equilibrium vapor concentration. The extent of vapor saturation is reflected by the saturation factor. For vapor recovery systems a saturation factor of 1.0 or completely saturated vapor is assumed in AP-42. ARB (Asregadoo 1992) bases the vapor space concentration on test data. The vapor space gas concentration represents the uncontrolled emissions from tank truck unloading (underground tank working losses), and vehicle tank working losses.

Vapor space concentrations from liquid fuels were estimated from the ideal gas law. Given a molar volume of 379.6 ft³/lb mole at 60°F, the equilibrium vapor (V_e) in a tank head space can be calculated from the following equation:

$$V_e (\text{lb/gal}) = MW (\text{lb/mol}) \times \text{lbmol}/379.6 \text{ ft}^3 \times 0.1337 \text{ ft}^3/\text{gal} \times \text{TVP}/14.7 \text{ psi} \times 520^\circ\text{R}/T \quad (1)$$

Where:

T = gas and liquid temperature (°R)

TVP = true vapor pressure (psi) at the equilibrium temperature

Table 4-28 shows the vapor space concentrations from various liquid fuels. Since the ARB inventory is based on test data that represents a range of gas temperatures and actual saturation conditions, a representative condition was modeled that reflects the inventory value. An effective fuel temperature was estimated for the ARB inventory values. The values in the top portion of Table 4-28 illustrate what temperature conditions would yield vapor concentrations that are consistent with the ARB inventory values (9.5, 1.0, and 10.0 lb/1000 gal for uncontrolled NMOG vapor mass). The 10 lb/1000 gal emission factor can then be calculated from a temperature of 80°F, TVP of 6.2 psi and vapor molecular weight of 70. A higher molecular weight corresponds to lower RVP gasolines since they contain less butane (MW=58). One could ignore the inventory data and simply project vapor emissions based on an assessment of vapor temperatures. This approach could be used to parametrically evaluate the effect of temperature on fuel-cycle emissions, but was not performed in this study. All of the emphasis was placed on comparison of emissions in the context of the State inventory values.

Vapor concentration (uncontrolled NMOG vapor mass) for this study was determined from equilibrium vapor densities that correspond to 70°F for underground tank vapors, and 80°F for vehicle fuel tank vapors. Actual vehicle vapor temperatures can be much higher.

The same temperature conditions can then be applied to a range of liquid fuels to generate vapor space concentrations or uncontrolled emission estimates that are consistent with California inventories. This effectively results in an equivalent equilibrium temperature that reflects the actual range of fuel temperatures and saturation conditions that correspond to test data. The underlying assumption with this approach is that the inventory data is based on a broad range of conditions and reflects the suitable conditions. Also shown in Table 4-28 are the vapor densities that would correspond to underground storage at 60°F and vehicle fuel storage at 100°F. These values were not used further in this study.

The inventory values reflect an equivalent equilibrium temperature of about 75°F for storage tank vapors. This value appears higher than what might be expected for soil temperatures. The effective temperature for vehicle tank vapors is 80°F that appears reasonable and agrees with fuel vapor and liquid measurements. Since this study is aimed at evaluating summer conditions these temperatures were used for estimating uncontrolled emissions.

Table 4-28. Evaporative Emissions from Local Fuel Distribution

Fuel/ Emission Category	RVP	Effective Temperature (°F)	Uncontrolled NMOG Vapor Mass (g/gal) (lb/1000gal)		Controlled NMOG Vapor (g/gal) ^a w. Control & Defect		TVP (psi)	MW (g/mol)
AP-42 sample calculation	10	80	4.56	10.0	0.228	—	6.6	66
ARB UG tank working loss	9.2	71	4.30	9.5	0.215	0.2152	5.90	68.5
ARB UG tank breathing loss	9.2	71	0.454	1.0	0.045	0.0454	5.9	68.5
ARB vehicle working loss	9.2	76	4.55	10.0	0.227	0.4433	6.29	68.5
Values for fuel cycle study ^b								
Diesel UG tank working loss	0.03	70	0.012	0.03	0.0125	0.0125	0.009	130
Diesel UG tank breathing loss	0.03	70	0.001	0.00	0.0012	0.0012	0.009	130
Diesel vehicle working loss	0.03	80	0.016	0.04	0.0163	0.0163	0.012	130
Diesel UG tank working loss	0.03	60	0.010	0.02	0.0105	0.0105	0.0074	130
Diesel UG tank breathing loss	0.03	60	0.001	0.00	0.0010	0.0010	0.0074	130
Diesel vehicle working loss	0.03	100	0.029	0.06	0.0289	0.0289	0.022	130
M100 UG tank working loss	4.5	70	0.683	1.50	0.0341	0.0341	2.00	32
M100 UG tank breathing loss	4.5	70	0.068	0.15	0.0068	0.0068	2.00	32
M100 vehicle working loss	4.5	80	0.871	1.92	0.0436	0.0849	2.60	32
M100 UG tank working loss	4.5	60	0.491	1.08	0.0246	0.0246	1.41	32
M100 UG tank breathing loss	4.5	60	0.049	0.11	0.0049	0.0049	1.41	32
M100 vehicle working loss	4.5	100	1.462	3.22	0.0731	0.1426	4.53	32

^a Working loss control factor = 95 percent, breathing control factor =90 percent, Defect rate = 5 percent for vehicle losses.

^b UG=Underground tank. UG tank losses are based on 70 F values. Vehicle losses are based on 80 F values. Emissions are also shown for 60 and 100°F for comparison but not used in this study. Vapor emissions are reduced 50 percent in Scenario 4.

The baseline 8.4 RVP gasoline was used to represent summer gasoline. This is different than the fuel used in the inventory that reflects year round fueling. The effective temperature for the inventory was first calculated from the average RVP. An effective summer and winter temperatures were then determined. The summertime temperatures for vehicle fueling were based on ARB fuel tank measurements. The wintertime temperature is consistent with the overall inventory. This approach, while somewhat arbitrary is based on reasonable temperature values and provides a basis for understanding the differences in emission factors used in this study and those in the State inventory.

Table 4-28 shows the vapor space NMOG for diesel and M100. Vapor emissions from reformulated diesel and FTD were assumed to be the same as those for diesel.

Table 4-28 also shows tank truck distribution emissions for liquid fuels. These emissions take into account vapor recovery effectiveness and a 5 percent defect rate for Stage II emission controls as indicated in Table 4-28. This combination of control effectiveness and defect rates will yield an emission factor lower than that used in State inventories. However, the inventories include uncontrolled fuel dispensing which is not relevant to this study.

4.9.2 LPG Distribution

LPG is stored and distributed in pressurized tanks. The fuel is stored in a liquid state at ambient temperature and the pressure in the tank is in equilibrium. At 70°F the storage pressure is 105 psig. When LPG is transferred from a storage tank to a tank truck, or to a vehicle fuel tank, a transfer pump provides about 50 psi of differential pressure. When fueling vehicle tanks, the fuel enters the tank and the LPG ullage condenses. This process can be accelerated with top loaded tanks where the liquid spray can absorb some of the heat from condensing the vapors.

The tank trucks are filled at refineries with a two hose system with one hose acting as a vapor return. Hoses are evacuated after fuel transfer operations at the refinery. Tank trucks can be filled to a safe fraction of its water capacity by weighing the truck during fueling (Lowi 1994), although this is not the current practice. However, current regulations require the use of an "outage" valve that indicates when the tank is full. Some LPG also enters the atmosphere from the fuel transfer fitting.

Table 4-29 shows the emissions associated with LPG storage and distribution. The LPG emissions correspond to the volume of liquid that escapes from the fuel transfer fitting divided by the amount of fuel transferred. Currently, LPG vehicles in California are equipped with an "outage" valve that indicates the 80 percent fill level by spilling LPG to the atmosphere. During vehicle fueling, the outage valve is opened and vapors pass through a 0.060-inch orifice and through the valve. When LPG reaches the 80 percent level in the vehicle tank, liquid enters the fill level line and exits into the atmosphere. A puff of white liquid is visible to the fueler that provides an additional signal that the tank

is full. California's vehicle code requires use of the outage valve. As indicated in Table 4-27, emissions from vehicle fueling are several grams per gallon.

Table 4-29: Fuel from LPG Fuel Delivery

Emission Source	Tank Volume (gal)	Liquid Spill Volume		Spill Rate (g/gal)
		(ml/fill)	(ml/gal)	
Transfer tank outage	10,000	—	—	1
Bulk tank outage	30,000	—	—	0.5
Truck fill outage ^a	—	—	—	2
Truck fill hose	3,000	1,391	0.139	0.070
Local tank hose	1,000	17.4	0.0017	0.0008
Local tank outage	—	—	—	5
Vehicle tank outage	—	—	—	0

^aBetter vapor management could eliminate this emissions source by the year 2010.

Many LPG tanks are already equipped with automatic stop-fill devices that could eliminate fuel tank vapor venting; however, Titles 8 and 13 of the California Administrative Code require the use of the outage valve. Other countries, including the Netherlands where many LPG vehicles operate, do not use the outage valve for fueling. One might expect that many LPG vehicles in California are fueled without using the outage valve if they are equipped with automatic stop fill devices.

A committee of NFPA, CHP, NPGA, and WLPGA representatives are working to set standards that will allow LPG vehicles to be fueled without leaking LPG to the atmosphere. Equipment that will minimize the fuel released from transfer fittings is also being approved (Wheeler 1994). EPA regulations on evaporative emissions from vehicles will also eliminate outage valve emissions.

Emission estimates for LPG fueling are based on the following conditions:

- 1391 cc loss from fuel couplings on 10,000 gal delivery trucks. Fluid loss is equivalent to 18 " of 1.25" (inner diameter) hose (Lowi 1992)
- Current vehicle hose coupling liquid losses are 7.57 cc (Lowi 1992) for a 12 gallon fuel transfer. Dry-break couplings would have less than 5 percent of the trapped volume of current LPG nozzles of the same capacity. The use of these nozzles is expected beyond the year 2000.
- Current fuel tank vapor displacement is based on sonic flow through a 1.5 mm orifice, 70°F tank temperature with a fuel pressure of 105 psig. Assuming an orifice discharge coefficient of 0.5 results in 2 g/s of vapor flow. With an 8 gal/min flow rate, vapor displacement is 15 g/gal.

- Vapor displacement from current tank truck filling assumes a 100 gal/min fill rate with an outage loss of 2 g/s.

4.9.3 Natural Gas Transmission and Distribution

Natural gas is transported through pipelines with compressors that maintain a pressure ranging from 220 to 1100 psi. A typical distribution pressure is 800 psi. Marginal gas will be transported from West Texas or Western Canada.

The compressor power, distance, and gas throughput for several pipeline projects was summarized by AGA (AGA 1993). The average energy use is 0.014 hp/Mmscf/d. Compression energy represented on a per mile basis ranged from 0.6 to 2 hp-hr/MMscf/mi with a weighted average of 0.9 hp-hr/MMscf/mi for Western States. Emissions from compressors are based on emission rates and transportation distances in Section 4.1. The emissions database calculates emissions in g/1000 mi/100scf. Compression energy usage is calculated in terms of a percentage of 1000 mi transported.

4.10 Toxic Emissions

California Assembly Bill AB 1807 created a comprehensive program to address adverse public health impacts from emissions of toxic substances to ambient air. Toxic air contaminants are an air pollutant that may cause or contribute to an increase in mortality or an increase in serious illness. A series of compounds were identified by ARB as toxic air contaminants, five of which are related to the combustion of fuels. They are 1,3-butadiene, benzene, formaldehyde, acetaldehyde, and diesel particulates. In addition, there are several compounds that are precursors to toxic air contaminants. Polycyclic aromatic hydrocarbons (PAH) and nitro-PAH are such precursors. Combustion compounds in diesel exhaust that are PAH and nitro-PAH are given in Table 4-30.

Toxic emissions and toxic precursors were estimated for diesel engine exhaust, diesel fuel, diesel fuel vapor, natural gas, liquid petroleum gas, refinery emissions, pipeline compression engine emissions, and power plant emissions. They are given in terms of milligrams of toxics per gram of NMOG in Table 4-31. Discussion of the findings can be found in the following subsections.

Table 4-30: Polycyclic Aromatic Hydrocarbons (PAH) and Nitro-PAH Found in Diesel Exhaust

PAH	Nitro-PAH
2,3,5-trimethyl naphthalene	1-nitronaphthalene
phenanthrene	2-nitronaphthalene
anthracene	methylnitronaphthalenes
me-phenanthrenes/anthracenes	2-nitrophenyl
fluoranthene	4-nitrophenyl
pyrene	5-nitroacenaphthalene
benzo[c]phenanthrene	2-nitrofluorene
benzo[ghi]fluoranthene	9-nitroanthracene
cyclopenta[cd]pyrene	1-nitropyrene
benz[a]anthracene	3-nitrofluoranthene
chrysene + triphenylene	4-nitropyrene
benzo[b+j+k]fluoranthene	7-nitrobenz[a]anthracene
benzo[e]pyrene	6-nitrochrysene
benzo[a]pyrene	6-nitrobenzo[a]pyrene
perylene	
indeno[1,23-cd]fluoranthene	
benzo[c]chrysene	
dibenz[a,j]anthracene	
indeno[1,23-cd]pyrene	
dibenz[a,h+a,c]anthracene	
benzo[b] chrysene	
benzo[ghi]pyrene	
coronene	
dibenzo[a,l]pyrene	
dibenzo[a,e]pyrene	
dibenzo[a,i]pyrene	
dibenzo[a,h]pyrene	

Table 4-31: Toxic and Precursor emissions levels

Sources	Function (mg/g NMOG)					N-PAHs
	Benzene	1,3- Butadiene	Formaldehyde	Acetaldehyde	PAHs	
Diesel Exhaust	17.78	5.44	130	42.0	1.67	0.01
Diesel Fuel, Low Aromatic	0	0	0	0	9.36	ND
Diesel Vapor, Low Aromatic	0	0	0	0	9.36	ND
LPG from natural gas	0	0	0	0	0	0
LPG from petroleum	0	0	0	0	0	0
Refinery Combustion	ND	ND	124	ND	ND	ND
Power Plant Emissions	ND	ND	844	ND	ND	ND
Natural Gas IC Engine Exhaust	2.98	1.19	130	3.0	0	0

Diesel Exhaust

Diesel exhaust has been a subject of recent interest due to the fact that diesel particulates have been identified as a toxic air contaminant. In a recent study by CE-CERT for ARB diesel exhaust was speciated. Some earlier studies also speciated diesel exhaust, but not to the level given in “Evaluation of Factors that Affect Diesel Exhaust Toxicity”, ARB Contract No. 94-312, July 1998. In this report, diesel exhaust was measured from a Cummins L-10 engine using three diesel fuels including California low-aromatic diesel fuel. The results are shown in Table 4-32. These emissions were used to develop the emission factors in Table 4-31. Particulate emissions for this engine were 183 mg/bhp-hr.

Table 4-32. Diesel Exhaust emissions in mg/bhp-hr

Component	Emissions
THC	470
Methane	19
1,3 Butadiene	2.46
Benzene	8.03
Formaldehyde	58.75
Acetaldehyde	19.10
PAHs	0.752
Nitro-PAHs	0.004

Diesel Fuel and Vapor

Diesel fuel was analyzed and speciated in a report done by California Institute of Technology and Oregon State University entitled “Characterization and Control of Organic Compounds Emitted from Air Pollution Sources”, Final Report, ARB Contract number 93-329, April 1998. In this report, diesel fuel was shown to have no toxic air contaminants. PAHs were measured but n-PAHs were not. Data for PAHs in diesel fuel are shown in Table 4-30. Since no data can be found on diesel fuel vapor, it is assumed that the same levels of PAHs and other TACs are the same as in the fuel itself.

LPG and Natural Gas

Natural gas and by-product LPG contain standard hydrocarbons which is consistent with the long-term geological origin of the fuel. Refinery-based LPG contains oeliphns such as propane LPG analyses are generally not performed to the same detail as gasoline speciations. However, since both LPG and natural gas are lower hydrocarbon gases, no toxic air contaminants or precursors should be present.

Refinery Emissions

The petroleum refining industry converts crude oil into more than 2500 refined products, including LPG, gasoline, kerosene, aviation fuel, diesel fuel, fuel oils, lubricating oils and feedstocks for the petroleum industry. AP-42 gives emission factors for hydrocarbons and aldehydes for the various processes of petroleum refining. It is

assumed that all petroleum refineries in the South Coast have emission control devices in place, thus the controlled emission factors were used. These are given in Table 4-33 for the various refinery processes. Over 99 percent of the hydrocarbons coming from a refinery are non-methane. While only total aldehyde emissions are given, it is assumed that the majority are formaldehyde.

Table 4-33. Controlled refinery emissions in lb/1000 ft³ of gas

Process	HC	Aldehydes
Fluid Catalytic Cracking	0	0
Moving-Bed Catalytic Crackers	87	12
Fluid Cooking Beds	0	0
Compressors	21.8	1.61
Vapor Recovery Systems	0.8	0
Vacuum Distillation	0	0

Power Plant Emissions

Emission factors for the generation of electricity using large controlled gas turbines are also given in AP-42. It is assumed that all power plant gas turbines in the South Coast use selective catalytic reduction with water injection as the emission control device. Emission factors from AP-42 are given in Table 4-34.

Table 4-34. Emission Factors for Large Controlled Gas Turbines in lb/MMBtu Fuel Input

Compound	lb/MMbtu
NMHC	0.0032
Formaldehyde	0.0027

Natural Gas IC Engine Exhaust

Natural gas-fired internal combustion engines are used in the natural gas industry at pipeline compressor and storage stations. These engines provide power to drive the compressors. At pipeline compressor stations, the engine is used to move natural gas from station to station. It is assumed that all pipeline engines in the South Coast are controlled. While AP-42 gives emission factors for these type of engines, better speciated exhaust emissions for natural gas IC engines can be found from Phase 2 of the Auto/Oil Air Quality Improvement Research Program. In this program, three CNG vehicles were tested on four different natural gas fuels. Both engine out and tailpipe were measured. Since pipeline engines are controlled in the South Coast but not to the level found in CNG vehicles, the engine out and tailpipe emission levels from the Auto/Oil program were ratioed at 25 percent/75 percent respectively. This gave

emission factors for benzene that were close the AP-42 values. Engine-out and tailpipe emission factors from the Auto/Oil program are given in Table 4-35.

Table 4-35. Weight percent of total hydrocarbon emissions for CNG vehicles

	Engine	Tailpipe
1,3-Butadiene	0.046	0.001
Benzene	0.072	0.016
Formaldehyde	3.867	0.434
Acetaldehyde	0.234	0.0435
Methane	78.937	93.734

5.0 Fuel Economy

Fuel-cycle emissions, including CO₂, correspond largely to the total volume of fuel produced. As such, fuel consumption is a strong driver in determining total fuel-cycle emissions. In general, as more fuel is produced, more feedstocks are extracted and transported, production facilities operate with greater throughput, and trucks and pipelines move more fuel to fueling stations. This section reviews the data inputs used in this study, methods for estimating fuel economy, and fuel economy assumptions that were used for the fuel-cycle analysis.

The goal of the study is to compare fuel cycle emissions from vehicles that are comparable to new Evs that would be produced in the year 2010. The analysis is aimed at a compact type vehicle that is consistent with many EV designs. Alternative fueled vehicles have been produced for a variety of vehicle classes. These include battery EV pick-up trucks and Evs designed for high energy efficiency. A comparison of vehicle types and fuel economy allowed for an estimate of fuel economy for consistent vehicles.

5.1 Fuel Economy Data and Projections

Fuel economy estimates for alternative fuel technologies were derived from comparisons of existing vehicles and model estimates for consistent vehicles. A consistent set of fuel economy estimates was determined by investigating the ratio of energy economy (mi/Btu) for alternative vehicle to comparable gasoline vehicles. These energy economy ratios (EERs) were then applied to a single baseline gasoline fuel economy. While gasoline fuel cycle emissions are not a part of this study, the baseline gasoline fuel economy provides a reference point for estimating alternative vehicle fuel economy.

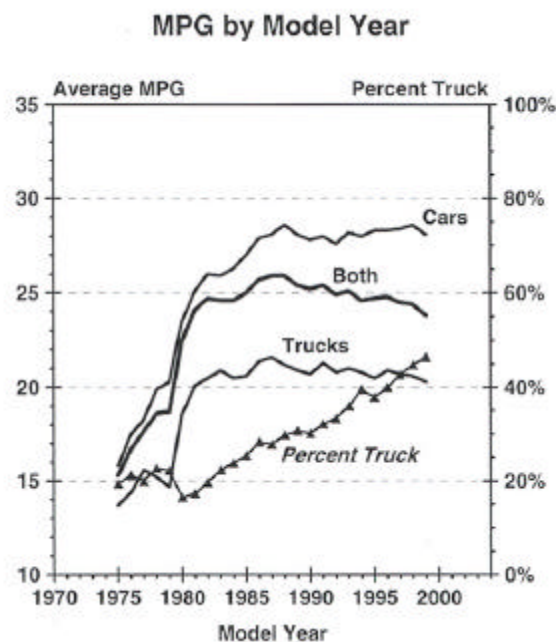
The U.S. EPA measures fuel economy for all certified vehicles, the U.S. Fuel Economy Guides were used to determine fuel economies for current vehicles. Limited production alternative fuel vehicles are also certified and listed in the Fuel Economy Guide. Advanced technologies, such as hybrids and fuel cells are at the prototype stage, but some tests and model predictions have been made relative to their fuel economy. These sources have been used to predict fuel economy for vehicles produced in 2010.

According to the U.S. EPA, after a surge in average fuel economy during the late 70's and gradual increases during the 1980's, average fuel economy has been on the decline. Though per-vehicle fuel economy has remained steady or only slightly decreased, the market shift to heavier SUVs and light trucks in the 1990's has brought the overall average down about 2.1 mpg to 25.9 mpg (U.S. EPA 1999). Figure 5-1 shows the U.S. EPA's estimate of average fuel economy trends for the past 25 years. One might expect

a continued gradual decline with no changes to CAFÉ or the fuel price market. The U.S. EPA's report also shows the variation between models sold in 1999. As shown in Figure 5-2, most passenger cars are estimated to achieve between 22 and 36 mpg, with a small percentage achieving more or less than this range. Similarly, over 80% of light trucks achieve between 15 and 23 miles per gallon, with most of the rest achieving up to 32 mpg. This sales fraction data is useful in determining the possible shifts in fuel economy trends.

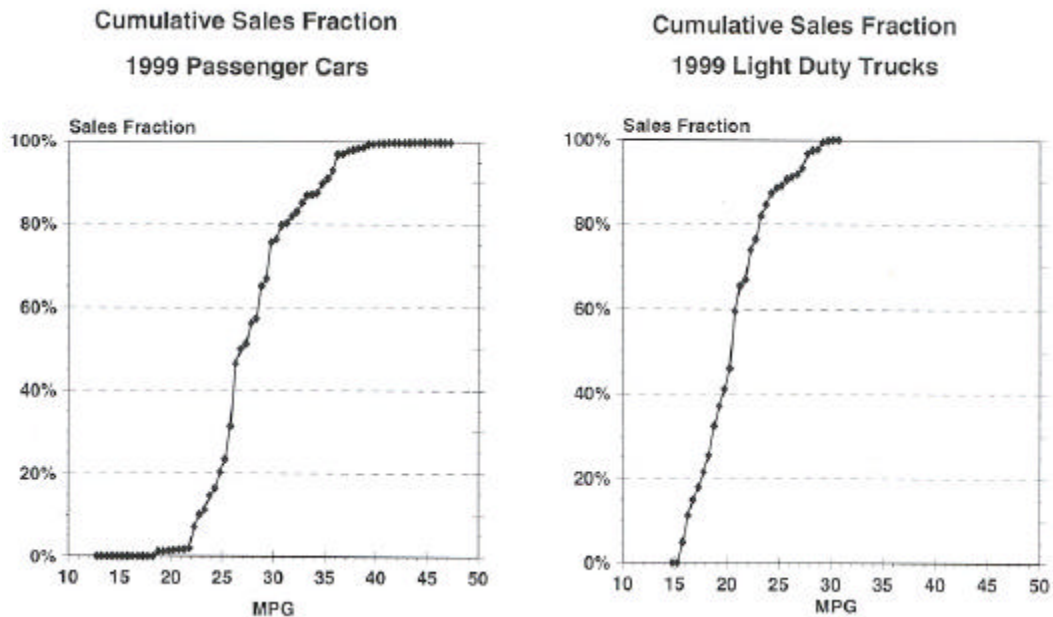
The comparison of fuel cycle emissions is intended to represent a significant volume of vehicles that could be certified as PZEVs. These PZEV vehicles could displace battery ZEVs so the types of vehicles represented in this study are intended to be a consistent type of vehicle. These comparisons would then represent vehicles in similar classes and performance capabilities. This is not necessarily straightforward, as various vehicles have different attributes that are particular to the technology and cannot be replicated in another vehicle technology. This will be discussed further in the following subsections.

Figure 5-1. Fuel Economy Trends, 1999



Source: U.S. EPA 19

Figure 5-2. Sales Fractions of 1999 Passenger Cars and Light Duty Trucks by Fuel Economy



Source: U.S. EPA 1999

5.2 Effect of Vehicle Stock Mix

Alternative vehicle fuel economy was estimated from a baseline gasoline vehicle fuel economy for a subcompact car class.

Alternatively, one could estimate the fuel economy of the *class or size* of the replaced vehicle as the baseline. This approach is more suitable for comparing alternative fueled vehicles to gasoline vehicles rather than evaluating vehicle that would be likely PZEV candidates.

Fuel economy ratios were estimated for each technology/fuel. These ratios are indications of how much more each technology would expect to achieve in terms of fuel economy (on an energy basis) compared to the baseline conventional vehicle. Since it is not possible to obtain fuel economy data for a consistent set of vehicles with similar attributes, fuel economy is estimated from energy efficiency data and the fuel's heating value. The Energy Economy Ratio (EER) is the ratio of alternative vehicle energy

economy to the baseline gasoline vehicle energy economy (on a lower heating value basis). These values were based upon data shown above.

EER values can be compared for different vehicles where the baseline and alternative vehicle are identical models. EER values are determined for various vehicle combinations and used to calculate the fuel economy for a consistent vehicle or mix of vehicles. For example, if a diesel car operates with a fuel economy of 33 mpg and a similar gasoline vehicle operates with a fuel economy of 24.9 mpg, the energy economy is 0.00044 km/kJ (2260 kJ/km) for the diesel vehicle and 0.00033 km/kJ (3000 kJ/km) for the gasoline vehicle.

5.3 Estimating the Fuel Economy of the Alternative Vehicle

Fuel economy ratios were estimated for each technology/fuel. These ratios are indications of how much more each technology would expect to achieve in terms of fuel economy (on an energy basis) compared to the baseline conventional vehicle. Since it is not possible to obtain fuel economy data for a consistent set of vehicles with similar attributes, fuel economy is estimated from energy efficiency data and the fuel's heating value. The Energy Economy Ratio (EER) is the ratio of alternative vehicle energy economy to the baseline gasoline vehicle energy economy (on a lower heating value basis). Baseline gasoline vehicles listed in the EPA Fuel Economy Guide are operated on Indolene during the test which has a lower heating value of 114,424 Btu/gallon. A list of EERs for the fuels and technologies examined in this study are shown in Table 5-1. Derivation of the EERs for each technology/fuel are discussed in the following subsections.

Table 5-1: Energy economy ratios for fuel cycle analyses

Technology/Fuel	2000		2010		
	EER	Weight Ratio	EER High	EER Low	Weight Ratio
Gasoline	1.00	1.00	1.00	1.00	1.00
Diesel, FTD DI CI	1.37	1.02	1.37	1.21	1.02
RFG HEV	1.53	1.00	1.45	1.30	1.00
LPG ICE	—	—	1.08	0.98	1.05
Methanol SR/PEMFC	—	—	1.54	1.39	1.50
Hydrogen PEMFC	1.57	—	1.74	1.50	1.50
Battery EV	2.85	1.29	2.90	2.40	1.25

A — no data available for FUDS cycle for current vehicles

5.3.1 Baseline Gasoline Vehicles

Baseline fuel economies were determined for one class of vehicles, namely subcompacts. Subcompacts represent one of the most fuel-efficient classes of vehicles and many of the advanced technology vehicles are in this class. Sixty-eight model year 2000 vehicles within this class were averaged (high performance vehicles were eliminated from the data – see Appendix A for the list of vehicles). Using undiscounted fuel economies⁶ the average fuel economy for the 68 vehicles was 32.26 miles per gallon. To account for real world conditions, this fuel economy were discounted by 15% resulting in a fuel economy of 27.42 mpg. Assuming a 10% improvement in fuel economy between 2000 and 2010, the average baseline fuel economy is 30.16 mpg.

Several of the advanced technologies are super efficient vehicles and should be compared to a super efficient baseline vehicle. This class similar to the Partnership for the New Generation of Vehicles (PNGV). It is expected that this class of vehicles will be 50% more efficient than the typical subcompact, resulting in a baseline fuel economy of 45.2 mpg (on-road estimate). The PNGV program estimates a CAFÉ value of 52 mpg for gasoline vehicles with conventional drive trains which is consistent with the on road value of 45.2 mpg.

5.3.2 Diesel Vehicles

Only Volkswagen currently produces light-duty diesel vehicles in the United States. Three models of diesel vehicles were compared against their gasoline counterpart, namely the Golf, Jetta, and New Beetle. Using a lower heating value for diesel fuel of 130,800 Btu/gallon, the average fuel economies for the model year 2000 automatic transmission versions of these vehicles were compared, resulted in an EER of 1.37 as shown in Table 5-2. Weight comparisons indicated the diesel vehicles to be about 2% heavier than their gasoline counterparts.

Table 5-2: Diesel Energy Economy Ratio

Model	Diesel Version mpg	Gasoline Equivalent mpep	Gasoline Version mpg	EER
New Beetle	44.7	39.1	28.5	1.37
Golf	44.7	39.1	28.5	1.37
Jetta	44.7	39.1	28.5	1.37

⁶ The EPA Fuel Economy Guide lists discounted fuel economy results to account for real world driving. Undiscounted values are published at EPA's Fuel Economy website (www.fueleconomy.gov). Undiscounted values provide a better comparison among various alternative technologies and fuels.

In a separate analysis, CEC examined 176 European direct-injected diesel vehicles and compared them against 831 European gasoline vehicles of the same class. This resulted in an EER of 1.21. Thus the range of EERs for future diesel vehicles was assumed to be the same as current vehicles, namely 1.21 to 1.37.

5.3.3 LPG Vehicles

No LPG vehicles are currently available from major manufacturers. EER values for LPG were estimated from CNG data and prior experience with LPG vehicles.

Several models of compressed natural gas vehicles were compared against their gasoline counterpart as shown in Table 5-3. EERs varied from 0.94 to 1.00 with the average being 0.98. Discussions with vehicle manufacturers have indicated that improvements in technology, such as port injection, will improve CNG fuel economy and should increase EERs as high as 1.08. Weight comparisons for the vehicles listed in Table 5-3 indicate that the CNG vehicles are 7% heavier than their gasoline counterparts.

Table 5-3: CNG Energy Economy Ratios

Model	CNG Version m/100 scf	Gasoline Equivalent mpep	Gasoline Version mpg	EER
Chevrolet Cavalier	19	23	24	0.94
Honda Civic	25	31	31	1.00
Toyota Camry	21	25	26	0.99
Ford Contour	19	23	23	1.00

5.3.5 Fuel Cell Vehicles

Prototype hydrogen fuel cell vehicles built by Ford and Daimler-Chrysler have been tested on U.S. driving cycles, but have no direct gasoline equivalent. Steam reformed methanol vehicles and partial oxidation reformer gasoline fuel cells are being tested in the laboratory. Several academic institutions have developed computer models of fuel cell vehicles to predict fuel economy for these technologies. Using this limited data, EERs of 1.50 to 1.74 have been estimated for hydrogen fuel cell vehicles, 1.39 to 1.54 for methanol steam reformed fuel cell vehicles. These estimates are highly speculative and will need to be refined as these technologies become more commercial.

5.3.5 Electric Vehicles

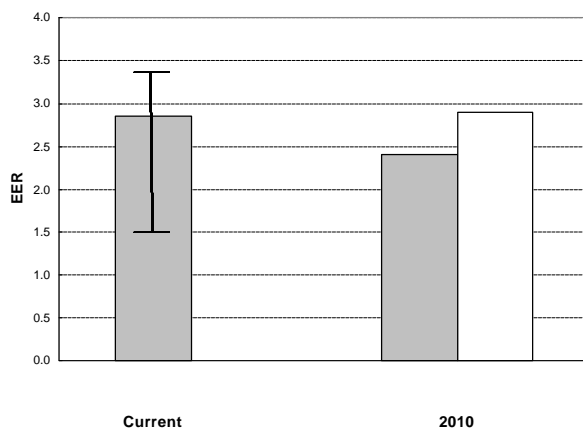
Several models of electric vehicles are currently in production both in the passenger car and light truck classes. Only the light truck and minivan classes have gasoline equivalent vehicles. The passenger car electric vehicles are specialty built vehicles with no direct gasoline comparison. In addition, electric vehicle technology is vastly more advanced than current gasoline technology, particularly in the light truck class.

Furthermore, the Federal test procedure for certifying electric vehicles tends to provide biases in regards to battery technology. While the average EER for the vehicles shown in Table 5-4 is 2.85, the authors believe that 2010 gasoline technology when compared to 2010 electric vehicle technology in equivalent vehicles will yield EERs between 2.4 and 2.9.

Table 5-4: Electric Vehicle Energy Economy Ratios

Electric Vehicle			Gasoline Vehicle		
Model	FE kWh/mi	FE (mpg)	Model	FE (mpg)	EER
`00 Ford Ranger – PbA	0.405	82.7	`00 Ford Ranger	25.5	3.24
`00 Ford Ranger – NiMH	0.421	79.5	`00 Ford Ranger	25.5	3.12
`99 Chrysler EPIC – NiMH	0.696	48.1	`99 Dodge Minivan	25.9	1.86
`98 Chevy S10 – PbA	0.431	77.7	`98 Chevy S10	25.3	3.07
`98 Chevy S10 – NiMH	0.546	61.3	`98 Chevy S10	25.3	2.43
`99 Honda EV Plus – NiMH	0.499	67.1	`99 Honda Civic/Accord	32.7	2.05
`99 GM EV-1 – NiMH	0.321	104.4	`99 Acura Integra	31.9	3.27
`99 GM EV-1 - PbA	0.280	119.6	`99 Acura Integra	31.9	3.75

Figure 5-3. ???



5.4 Fuel Economy Cases

Using the EERs from Table 5-1 and the average gasoline fuel economy of 27.42 mpg for current vehicles, 30.16 mpg for 2010 gasoline subcompact vehicles, and 45.24 mpg for 2010 gasoline super efficient vehicles, the fuel economies shown in Table 5-5 are calculated. Five fuel economy cases are defined below:

- Case a – Current vehicles and current EERs
- Case b – 2010 subcompact vehicles using 2010 high EER estimates
- Case c – 2010 subcompact vehicles using 2010 low EER estimates
- Case d – 2010 super efficient vehicles using 2010 high EER estimates
- Case e – 2010 super efficient vehicles using 2010 low EER estimates

Table 5-5: Fuel economy cases used in fuel cycle analyses

Fuel (unit)	Vehicle	Case	LHV (Btu/unit)	EER	Fuel Economy
Gasoline	Conventional ICE	a	114,244	1.00	27.42 mi/gal
Diesel	IDI CI	a	130,800	1.37	43.01 mi/gal
FT Diesel	—	a	118,800	—	—
LPG	Conventional ICE	a	83,200	0.98	19.57 mi/gal
Methanol	—	a	57,000	—	—
Electric	Battery EV	a	3,412	2.85	2.33 mi/kWh
Gasoline	Conventional ICE	b	114,244	1.00	30.16 mi/gal
Diesel	IDI CI	b	130,800	1.37	47.31 mi/gal
FT Diesel	IDI CI	b	118,800	1.37	42.97 mi/gal
LPG	Conventional ICE	b	83,200	1.08	23.72 mi/gal
Methanol	SR/PEM Fuel Cell	b	57,000	1.54	23.18 mi/gal
Hydrogen	PEM Fuel Cell	b	51,600	1.74	23.70 mi/lb
Electric	Battery EV	b	3,412	2.90	2.61 mi/kWh
Gasoline	Conventional ICE	c	114,244	1.00	30.16 mi/gal
Diesel	IDI CI	c	130,800	1.21	41.79 mi/gal
FT Diesel	IDI CI	c	118,800	1.21	37.95 mi/gal
LPG	Conventional ICE	c	83,200	0.98	21.53 mi/gal
Methanol	SR/PEM Fuel Cell	c	57,000	1.39	20.92 mi/gal
Hydrogen	PEM Fuel Cell	c	51,600	1.50	20.43 mi/lb
Electric	Battery EV	c	3,412	2.40	2.16 mi/kWh
Gasoline	Conventional ICE	d	114,244	1.00	45.24 mi/gal
Diesel	IDI CI	d	130,800	1.37	70.97 mi/gal
FT Diesel	IDI CI	d	118,800	1.37	64.46 mi/gal
LPG	Conventional ICE	d	83,200	1.08	35.59 mi/gal
Methanol	SR/PEM Fuel Cell	d	57,000	1.54	34.76 mi/gal
Electric	Battery EV	d	3,412	2.90	3.92 mi/kWh
Gasoline	Conventional ICE	e	114,244	1.00	45.24 mi/gal
Diesel	IDI CI	e	130,800	1.21	62.68 mi/gal
FT Diesel	IDI CI	e	118,800	1.21	56.93 mi/gal
LPG	Conventional ICE	e	83,200	0.98	32.29 mi/gal
Methanol	SR/PEM Fuel Cell	e	57,000	1.39	31.38 mi/gal
Electric	Battery EV	e	3,412	2.40	3.24 mi/kWh

6.0 Emission Calculations

Emissions per unit of fuel were calculated for the fuel and feedstock combinations discussion in Section 3.

Results are shown here for the year 2010 corresponding to Scenarios 2 and 3. The results for average emissions and for 1996 are included in Volume 2. The results were organized according to fuel economy cases presented in Section 5.

Table 6-1 shows the marginal NMOG emissions for Scenario 2 on a g/gal basis (per kWh for electric power). These emissions represent the values for the different fuel production and distribution phases discussed in Section 3. Many of the emission sources were estimated to be zero on a marginal basis. Crude oil extraction and transport emissions would not change with additional diesel or LPG usage. It is assumed that additional finished fuel is transported to the SoCAB to represent the marginal fuel input to refineries. In the case of diesel, the mix of refinery operations would be adjusted to accommodate an increase in diesel production. Such a switch is typically performed on a larger scale in the winter for some refineries when they produce more home heating oil and less gasoline. Marginal feedstock transport and fuel production emissions in the SoCAB are zero for methanol and FTD production from remote natural gas. When landfill gas is converted to methanol, additional emissions would be produced from the methanol plant but net emissions from the landfill would be reduced or zero. The NMOG emissions for LPG transport are much higher than those for other fuels. These emissions correspond to the outage value losses from distribution storage tanks, tank trucks, and local fueling stations. This source was assumed to be controlled in Scenario 3.

Table 6-2 shows the marginal emission estimates for Scenario 3. In this scenario, additional emission controls were assumed. The most significant emission reduction assumptions were vapor recovery on methanol and diesel fueling equipment and reductions in spillage emissions per ARB's new rules for enhanced vapor recovery. A 90 percent reduction in emissions could be accomplished with on-board vehicle refueling vapor recovery. A lower emission factor for fuel spillage was also assumed. This scenario does not take into account the use of larger vehicle fuel tanks to extend range and reduce spillage emissions.

Tables 6-3 and 6-4 show the emissions for Scenarios 2 and 3 on a g/mi basis. Fuel economy assumptions b and c were applied to g/gal values. The results are also shown in Figures 6-1 and 6-2. These g/mi representations straddle the high and low estimates for Case B.

Table 6-1: Marginal NMOG Emissions per Unit Fuel: Scenario 2

Fuel-Cycle Process	NMOG Emissions (g/gal)						g/kWh
	Diesel	RFD	LPG	FTD	M100 NG	M100 LFG	Electric
Feedstock transport	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0007
Refinery	0.0000	0.0020	0.0000	0.0000	0.0000	0.0020	0.0061
Fuel Transport	0.0027	0.0027	0.0027	0.0027	0.0027	0.0027	0.0000
Fuel Unloading	0.0036	0.0036	0.6000	0.0036	0.0063	0.0063	0.0000
Bulk Terminal	0.0036	0.0036	0.0017	0.0036	0.0063	0.0063	0.0000
Truck Spillage	0.0200	0.0200	0.0008	0.0200	0.0200	0.0200	0.0000
Truck Exhaust	0.0120	0.0120	0.0085	0.0110	0.0109	0.0109	0.0000
Truck Unloading	0.0100	0.0100	2.0000	0.0100	0.0246	0.0246	0.0000
Storage Tank Breathing	0.0010	0.0010	0.0000	0.0010	0.0490	0.0490	0.0000
Vehicle Working Loss	0.016	0.016	0.080	0.016	0.044	0.044	0.000
Spillage	0.140	0.140	0.084	0.130	0.070	0.070	0.000
Total	0.209	0.211	2.778	0.198	0.233	0.235	0.007

Table 6-2: Marginal NMOG Emissions per Unit Fuel: Scenario 3

Fuel-Cycle Process	NMOG Emissions (g/gal)						g/kWh
	Diesel	RFD	LPG	FTD	M100 NG	M100 LFG	Electric
Feedstock transport	0.000	0.000	0.000	0.000	0.000	0.000	0.0005
Refinery	0.000	0.001	0.000	0.000	0.000	0.001	0.0062
Fuel Transport	0.0022	0.0022	0.0022	0.0022	0.0022	0.0000	0.000
Fuel Unloading	0.0014	0.0014	0.0480	0.0014	0.0025	0.0000	0.000
Bulk Terminal	0.0014	0.0014	0.0007	0.0014	0.0025	0.0025	0.000
Truck Spillage	0.0080	0.0080	0.0003	0.0080	0.0080	0.0080	0.000
Truck Exhaust	0.0096	0.0096	0.0068	0.0088	0.0087	0.0087	0.000
Truck Unloading	0.0100	0.0100	0.0000	0.0100	0.0246	0.0246	0.000
Storage Tank Breathing	0.0010	0.0010	0.0000	0.0010	0.0490	0.0490	0.000
Vehicle Working Loss	0.0016	0.0016	0.0080	0.0016	0.0044	0.0044	0.000
Spillage	0.140	0.140	2.778	0.130	0.070	0.070	0.000
Total	0.175	0.176	0.150	0.164	0.172	0.168	0.007

Table 6-3: NMOG Emissions per Mile Driven: Scenario 2b

Fuel-Cycle Process	Diesel	RFD	LPG	FTD	M100 NG	M100 LFG	Electric
Fuel Economy (mi/gal)	41.4	40.8	21.3	37.6	20.7	20.7	2.15
Feedstock transport	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00032
Refinery	0.00000	0.00006	0.00000	0.00000	0.00000	0.00009	0.00259
Fuel Transport	0.00008	0.00008	0.00024	0.00009	0.00013	0.00013	0.00000
Fuel Unloading	0.00010	0.00010	0.03567	0.00012	0.00029	0.00029	0.0000
Bulk Terminal	0.00010	0.00010	0.00010	0.00012	0.00029	0.00029	0.0000
Truck Spillage	0.00058	0.00058	0.00005	0.00064	0.00094	0.00094	0.0000
Truck Exhaust	0.00035	0.00035	0.00051	0.00035	0.00051	0.00051	0.0000
Truck Unloading	0.00029	0.00029	0.11891	0.00032	0.00115	0.00115	0.0000
Storage Tank Breathing	0.00003	0.00003	0.00000	0.00003	0.00229	0.00229	0.0000
Vehicle Working Loss	0.00047	0.00047	0.00476	0.00052	0.00204	0.00204	0.0000
Spillage	0.00338	0.00343	0.00394	0.00346	0.00338	0.00338	0.0000
Total	0.00505	0.00518	0.13047	0.00527	0.01128	0.01137	0.0028

Table 6-4: NMOG Emissions per Mile Driven: Scenario 3c

Fuel-Cycle Process	Diesel	RFD	LPG	FTD	M100 NG	M100 LFG	Electric
Fuel Economy (mi/gal)	46.9	46.4	23.5	42.6	23	23	2.59 mi/kWh
Feedstock transport	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00003
Refinery	0.00000	0.00003	0.00000	0.00000	0.00000	0.00004	0.0094
Fuel Transport	0.00006	0.00006	0.00012	0.00006	0.00009	0.00000	0.0000
Fuel Unloading	0.00004	0.00004	0.00259	0.00004	0.00011	0.00000	0.0000
Bulk Terminal	0.00004	0.00004	0.00004	0.00004	0.00011	0.00011	0.0000
Truck Spillage	0.00021	0.00021	0.00002	0.00023	0.00035	0.00035	0.0000
Truck Exhaust	0.00025	0.00025	0.00037	0.00026	0.00038	0.00038	0.0000
Truck Unloading	0.00026	0.00026	0.00000	0.00029	0.00106	0.00106	0.0000
Storage Tank Breathing	0.00003	0.00003	0.00000	0.00003	0.00212	0.00212	0.0000
Vehicle Working Loss	0.0000	0.0000	0.0004	0.0000	0.0002	0.0002	0.0000
Spillage	0.0030	0.0030	0.0036	0.0031	0.0030	0.0030	0.0000
Total	0.00369	0.00373	0.00629	0.00381	0.00738	0.00727	0.00259

Figure 6-1: Marginal NMOG Emissions in the SoCAB (Scenario 2c)

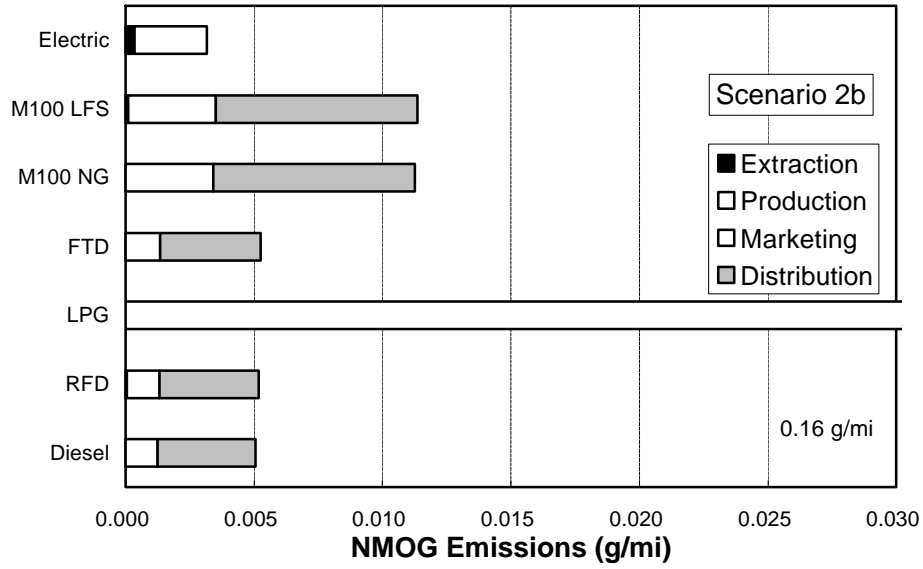


Figure 6-2: Marginal NMOG Emissions in the SoCAB (Scenario 3c)

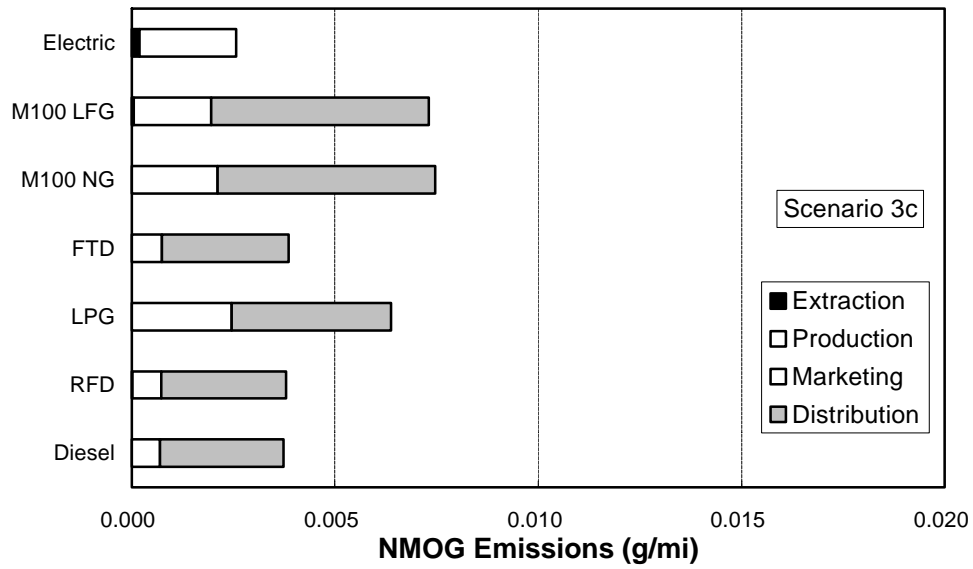


Figure 6-3 shows the range of NMOG emissions for Case B that encompasses fuel-cycle Scenarios 2 and 3 and fuel economy assumptions b and c. The range in emissions is due to vehicle fuel efficiency assumptions and the assumptions on fuel-cycle emissions. The large value for LPG corresponds to refueling venting emissions from service station storage tanks. Figure 6-4 shows the results for Scenario 3 alone. Here the range in results is due to range in vehicle fuel efficiency.

Table 6-5 and Figure 6-5 show the marginal NO_x for Scenario 2b, which corresponds to the high range of Case B. As these values are uniformly low, the lower estimates for Scenario 3 are not shown. NO_x emissions are higher for LPG transport as the fuel is transported into the SoCAB by railcar. Marginal NO_x from power generation is counted as zero since this pollutant is capped under the RECLAIM program.

Figure 6-6 shows the Global CO_2 emissions for Case B. Both vehicle exhaust and energy inputs for fuel production are included.

Table 6-6 shows toxic emissions for marginal emission assumptions in the SoCAB. The toxic components for each source were summed with the emission sources in Table 6-1. The values are shown on a g/gal and g/mi basis (using fuel economy assumption b). The most notable emissions are toxics from diesel combustion and formaldehyde from power plants.

Figure 6-3: Marginal Range in Fuel-Cycle NMOG Emissions — Case B (Scenarios 2b, 2c, 3b, 3c)

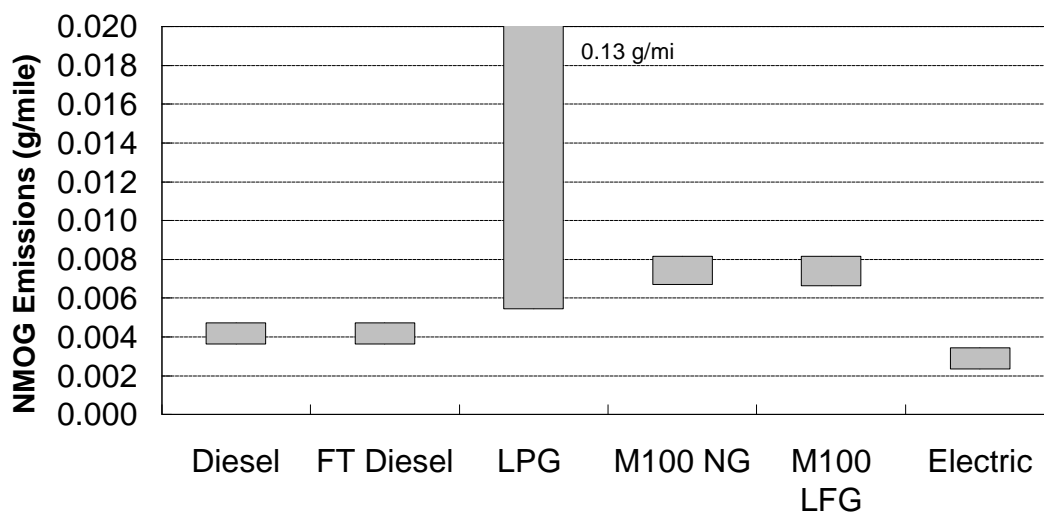


Figure 6-4: Range in Marginal Fuel-Cycle NMOG Emissions for Scenario 3

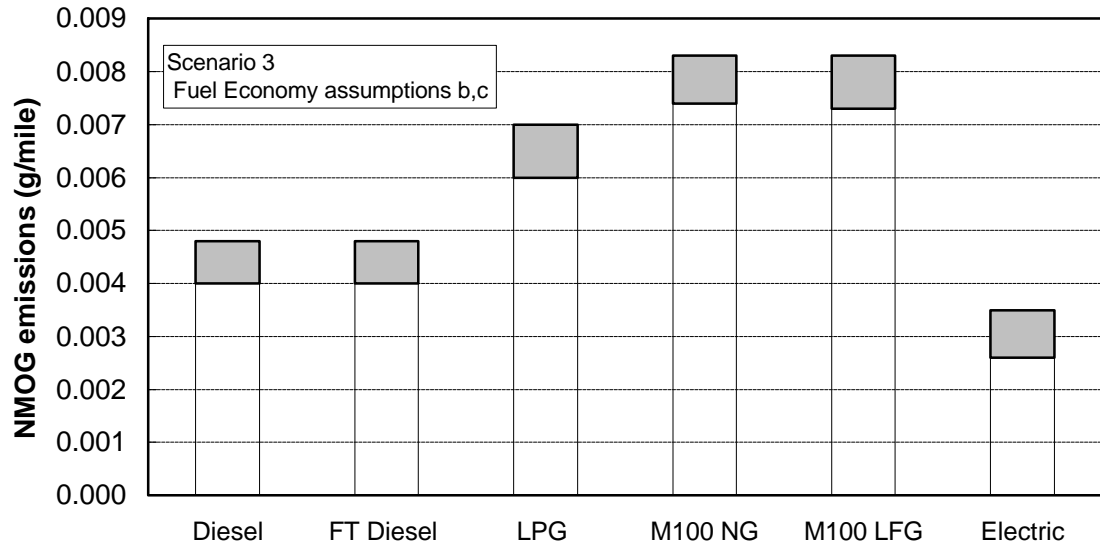


Table 6-5: Marginal NO_x Emissions per Unit Fuel (Scenario 2)

	NO _x (g/gal)				g/kWh	
	Diesel	RFD	LPG	FTD	M100 NG	M100 LFG
Feedstock transport	0.0000	0.0000	0.0000	0.0000	0.0000	0.0022
Refinery	0.0000	0.0000	0.0000	0.0000	0.0000	0.0020
Fuel Transport	0.0357	0.0357	0.0700	0.0357	0.0342	0.0000
Truck Exhaust	0.0600	0.0600	0.0900	0.0600	0.0600	0.0600
Total	0.096	0.096	0.160	0.096	0.094	0.062

Figure 6-5: Marginal NO_x emissions in the SoCAB (Scenario 2b)

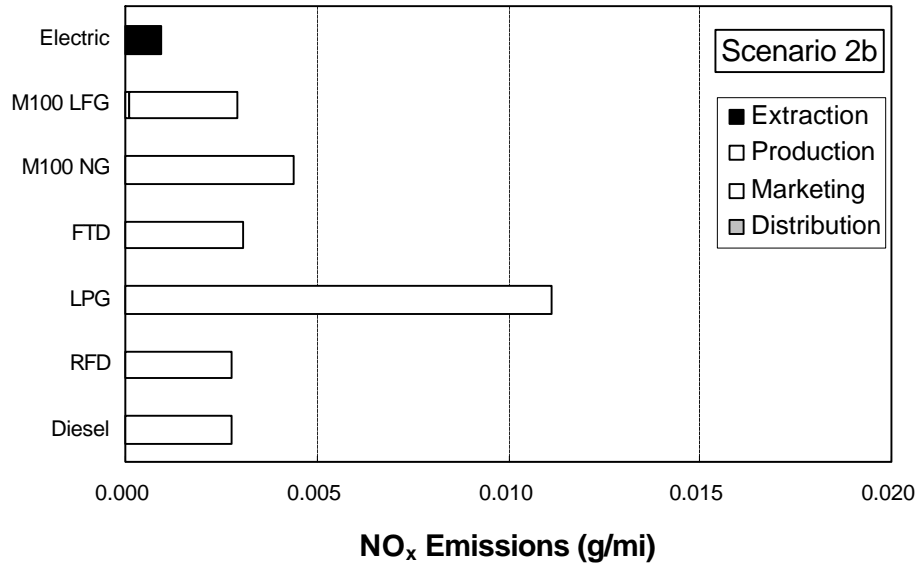


Figure 6-6: Global CO₂ Emissions, Case B, Marginal Fuel Sources

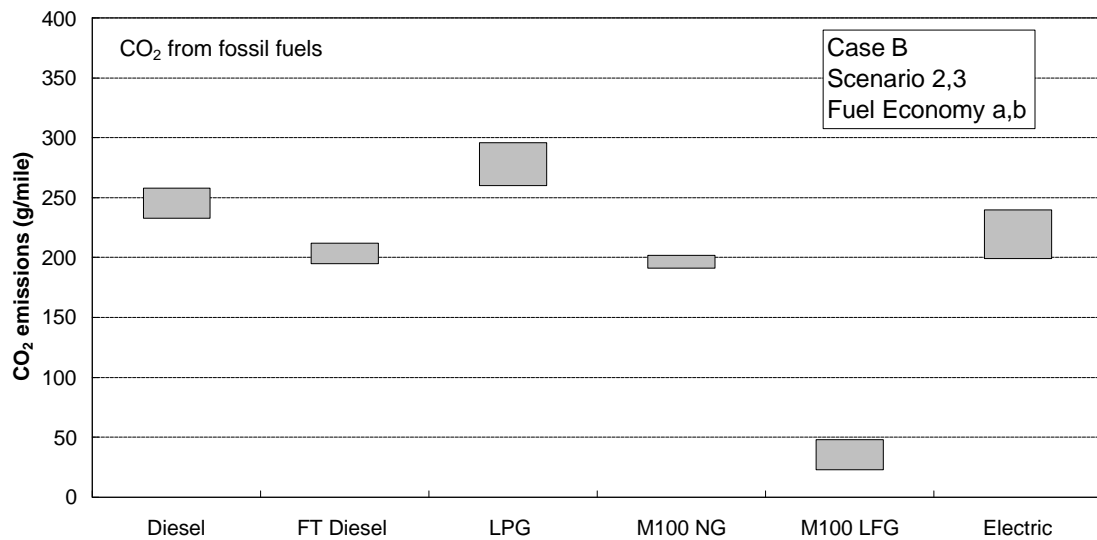


Table 6-6. Toxic Emissions (Scenario 3)

Toxics (mg/mi)	Diesel	RFD	LPG	FTD	M100 NG	M100 LFG	Electric
Benzene	0.0045	0.0045	0.0066	0.0046	0.0068	0.0068	0.0019
1-3 Butadiene	0.0013	0.0013	0.0020	0.0014	0.0020	0.0020	0.0000
Formaldehyde	0.0325	0.0325	0.0477	0.0332	0.0491	0.0491	0.0281
Acetaldehyde	0.0105	0.0105	0.0154	0.0107	0.0159	0.0159	0.0000
PAH	0.0082	0.0082	0.0006	0.0004	0.0006	0.0006	0.0000
Diesel Particulate	87	87	129	89	132	132	0

The effect of fuel economy on fuel cycle emissions was considered for Cases C and D. Case D is based on high efficiency vehicle fuel economy. The net effect of fuel economy improvements in Case D is a 33 percent reduction in fuel cycle emissions. This outcome depends to some extent on the trend in fuel tank size as vehicle fuel economy is improved. If fuel tank size were reduced in proportion to improvements in fuel economy, a 33 percent improvement in fuel economy would result in a somewhat smaller improvement in fuel cycle emissions.

The potential diesel, LPG, methanol, and electric vehicles to occupy different portions of the light-duty vehicle market were considered in Case C. The fuel economy calculations shown in Section 5 identify the magnitude of this effect. The shift in vehicle fuel economy due to expected vehicle market share is about 10 percent. For example, LPG vehicles are expected to displace larger gasoline vehicles with an average fuel economy of 19 mpg. This result indicates that the benefit of displacing gasoline vehicles would be greater than that of an electric vehicle. Similarly, the fuel cycle emissions from the LPG vehicles would be greater due to their larger size.

7.0 Conclusions

Fuel-cycle emissions were evaluated in the context of marginal emissions associated with marginal alternative fuel consumption or gasoline displacement. A moderately small use of alternative fuels would displace gasoline that would be imported into the SoCAB or allow for additional exports from the SoCAB, while a more aggressive alternative fuels penetration may lead to a reduction in refinery output. Small increments of alternative fuel use would displace emissions from fuel hauling, vehicle fueling, and possible marine vessels used to import refinery blending components. On a small scale, other market conditions will influence refinery emissions more substantially than gasoline displacement due to alternative fuel use, leaving the refineries in the SoCAB operating at capacity. Many alternative fuels would be produced outside the SoCAB. Their marginal emissions correspond largely to fuel trucking or distribution and local vehicle fueling.

Electricity for EVs in use in the SoCAB is generated in the basin, the rest of California, and outside of California. Marginal emissions from power generated in the SoCAB are limited by several factors. Existing facilities in the SoCAB could not increase emissions beyond current permit levels and new facilities would need to buy offsets. Power plants in the SoCAB are subject to RECLAIM that provides a cap on power plant NO_x emissions for each utility. If a utility is above its RECLAIM limit, it can install SCR on additional power plants or purchase NO_x offsets. If a utility is already at its emission cap or in a position where it needs to purchase offsets with respect to SoCAB RECLAIM, any incremental power generation for EVs will result in no additional NO_x emissions in the SoCAB. The CEC modeled the power generation requirements for baseline power and for EVs with several different power generation scenarios.

Based on CEC's analysis of the emissions of power plants with respect to their RECLAIM limits, marginal NMOG emissions from EVs, based on the CEC scenarios, are less than 0.01 g/mi.

Marginal emissions from diesel, and methanol distribution correspond to about 0.01 g/mi of NMOG. NMOG emissions from LPG distribution and fueling are currently very high due to vapor releases from fuel transfer operations. Vapor controls are assumed to be implemented for Scenario 3.

7.1 Emission Policy Considerations

The results of this study indicate that fuel spillage is a dominant source of fuel-cycle emissions if vehicle fueling vapor losses are eliminated. Once refueling vapor emissions are eliminated or are very low as in the case of diesel and methanol with ORVR, refueling spillage becomes the dominant source of NMOG. Spillage emissions in general tend to drop as fuel tank capacity is increased. For some vehicle technologies, fuel tank size will increase with lower fuel economy in order to maintain a constant range. While the consumer may not always utilize the full fuel tank capacity, the connection between marginal NMOG and fuel economy is weak.

One of the most significant questions with marginal fuel-cycle emissions is how to treat fuel economy. Several options for allowing credit for low fuel-cycle emissions are summarized below.

Base low fuel-cycle allowance on actual vehicle fuel economy

ARB could allow low fuel-cycle PZEV credits based on a vehicle's actual fuel economy weighted over the CAFÉ mix of city and highway driving. This approach has the advantage of not depending upon an assessment of vehicle fuel economy. Manufacturers would be incentivized to make vehicles more fuel efficient and lighter. ARB could publish a fuel-cycle rating for each fuel on a g/gal basis that the manufacturer could then divide by the vehicle fuel economy. Manufacturers could also improve the fuel-cycle emission score by increasing fuel tank capacity to reduce spillage emissions per gallon of fuel.

The disadvantage of this approach is that it primarily favors small passenger cars while trucks and SUVs are a growing part of the LDV mix. A small SULEV would likely displace the sale of another small car. Another disadvantage of this approach is that smaller vehicles balance out larger vehicles in the CAFÉ calculation.

Base low fuel-cycle allowance on assessment of vehicle fuel economy

ARB could certify fuels based on the results of this study. This approach recognizes that a variety of vehicles will be sold in the market and this study takes into account the likely effect of vehicle fuel economy. If the projected vehicle fleet fuel-cycle emissions were below or near 0.01 g/mi then the fuel would qualify. This approach would allow large vehicle to qualify for the low fuel-cycle allowance and would not provide an additional incentive to improve fuel economy or reduce CO₂ emissions. A large vehicle meeting SULEV exhaust would provide significant fuel-cycle emission reductions, primarily by eliminating refueling vapor emissions.

Base low fuel-cycle allowance on vehicle size category bins

In order to incentivize highly efficient vehicles and not bias the low fuel-cycle allowance towards smaller cars, ARB could provide minimum fuel economy requirements for each fuel and vehicle size category. This approach would allow manufacturers to make a highly efficient large vehicle and reduce fuel-cycle emissions when compared to other vehicle types.

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